Service Date: December 19, 2006

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER OF NORTHWESTERN ENERGY, Application for Approval of 2003 Avoided Cost Compliance Filing, Schedules QFLT-1 and STPP-1	)	UTILITY DIVISION DOCKET NO. D2003.7.86 ORDER NO. 6501f
IN THE MATTER OF NORTHWESTERN ENERGY, Application for Approval of 2004 Avoided Cost Compliance Filing, Schedules QFLT-1 and STPP-1	)	UTILITY DIVISION DOCKET NO. D2004.6.96 ORDER NO. 6501f
IN THE MATTER OF NORTHWESTERN ENERGY, Application for Approval of 2005 Avoided Cost Compliance Filing, Schedules QFLT-1 and STPP-1	)	UTILITY DIVISION DOCKET NO. D2005.6.103 ORDER NO. 6501f

FINAL ORDER

Appearances:

For the Applicant:

NorthWestern Energy -- Wayne Harper and Richard Garlish, 40 East Broadway, Butte, Montana 59701

For the Intervenors:

Montana Consumer Counsel -- Mary Wright, PO Box 201703, Helena, Montana 59620

Colstrip Energy Limited Partnership, Whitehall Wind, Boulder Hydro, et al. -- Michael Uda, 44 West Sixth Ave, Helena, Montana 59601

Before: Greg Jergeson, Chairman
Brad Molnar, Vice-Chairman
Doug Mood, Commissioner
Robert H. Raney, Commissioner
Thomas J. Schneider, Commissioner

Commission Staff: Michael Lee, Bureau Chief, Rate Design Bureau, Utility Division
Will Rosquist, Rate Analyst, Rate Design Bureau, Utility Division
Martin Jacobson, Staff Attorney, Legal Division

INTRODUCTION

1. In this order the Montana Public Service Commission (PSC or Commission) issues its decisions on three NorthWestern Energy (NWE) applications to revise qualifying facility (QF) rates, terms, and conditions. The PSC last addressed NWE's QF tariffs in PSC Docket No. D2002.7.80.[1] Federal and state laws require NWE to purchase energy and capacity from qualified cogeneration and small power producers.

2. In 1978, Congress enacted five energy-related bills, one of which was the Public Utility Regulatory Policies Act (PURPA). Among other things § 210 of PURPA encourages cogeneration and small power production by requiring electric utilities to purchase energy and capacity from QFs at rates not higher than a utility's incremental cost for alternative power, requires that the rates for purchases be just and reasonable to the electric consumers of the electric utility and in the public interest and that they do not discriminate against QFs, requires the Federal Energy Regulatory Commission (FERC) to establish rules to implement PURPA, and prohibits rates that exceed the incremental cost to the electric utility of alternative electric energy. FERC adopted rules on March 20, 1980 *(see e.g., 18 CFR 292)* addressing costs that form the basis for energy and capacity payments to QFs.

3. In 1981 the Montana Legislature enacted PURPA-related statutes, "Small Power Production Facilities," codified at §§ 69-3-601 through 69-3-604, MCA.[2] These statutes require any regulated public utility supplying electricity to purchase power from QFs. Public utilities and QFs may mutually agree to a price. If they cannot mutually agree, the statutes require the PSC to set rates within 120 days of receipt of a petition from a QF or a utility or before completing a rate proceeding involving QF rates. The PSC may set QF rates based on a public utility's avoided costs, the QF's cost of production, or any other another method that promotes QF development.

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1 *See* PSC Order No. 6434 (December 17, 2003).

2 The 2003 Montana legislature has placed these statutes in a "repealed on occurrence of contingency" status pending the effective date of any repeal of PURPA. *2003 Legislature, HB 417; Ch. 284, L. 2003; e.g. § 69-3-601, MCA.*

4. In 1981, the PSC adopted "Cogeneration and Small Power Production" rules, incorporating by reference FERC rules and establishing general requirements and criteria, including the respective obligations of QFs and utilities *(see ARM 38.5.1901 through 38.5.1908)*. These rules require, among other provisions, "standard" rates for QFs that do not negotiate a rate. The PSC amended the rules in 1992 to limit the availability of long-term contracts. For QFs that exceed 3 MWs in size, a long-term contract is available only if the QF is selected in a utility's all-source competitive solicitation. Between solicitations QFs larger than 3 MWs may receive either the "standard" short-term rate or an alternative short-term rate negotiated with the utility. The PSC sets standard long-term rates for QFs 3 MW and smaller. As amended, the rules also require compatibility between QF rates and the PSC's least-cost planning and acquisition guidelines *(ARM 38.5.2001 through 38.5.2012)*. *See ARM 38.5.1902(6)*.

5. In the 1980s, the PSC processed three generic QF dockets *(PSC Docket Nos. 81.2.15, 83.1.2, and 84.10.64)*. In each docket, the PSC established policies and QF rates. The PSC also established QF rates in limited purpose dockets. *See e.g., Matter of Billings Generation Inc., PSC Docket No. 90.8.51*.

6. The federal Energy Policy Act of 2005 (EPAct 2005) § 1253 continues to obligate certain utilities to purchase electric energy from QFs, so long as FERC finds that QFs do not have nondiscriminatory access to either: (1) an independently administered auction-based day-ahead and real-time wholesale market; (2) transmission and interconnection services administered pursuant to an open access, nondiscriminatory transmission tariff and competitive wholesale markets with a meaningful opportunity to sell energy and capacity to buyers other than the host utility; or (3) wholesale markets for the sale of capacity and energy that are, at a minimum, of comparable competitive quality as such markets.

7. On October 19, 2006, FERC finalized rulemaking modifying the mandatory power purchase obligations for electric utilities under PURPA. The rulemaking implements the mandate of the EPAct2005. The rule establishes a rebuttable presumption that, except for QFs with a net capacity not greater than 20 MWs, QFs have nondiscriminatory access to markets if they are eligible for service under FERC-approved

open access transmission tariff or a reciprocity tariff filed by non-jurisdictional transmission owners. For those QFs 20 MWs and less, the rule also establishes a rebuttable presumption that the purchase obligation remains in effect in all markets.

PROCEDURAL HISTORY

8. The procedural history in these three consolidated dockets is extensive. On June 30, 2003, NWE submitted its Annual Avoided Cost Compliance filing in PSC Docket No. D2003.7.86. NWE's filing included a motion for an interim increase, a motion for a protective order, and a request for interim approval of Short-Term Power Purchase (STPP) and Qualifying Facility Long-Term (QFLT) rates. NWE asserts it performed an "incremental calculation" to establish rate variables consistent with the stipulation in PSC Docket No. D2002.7.80.

9. On July 17, 2003, Colstrip Energy Limited Partnership (CELP) petitioned to intervene and filed nondisclosure agreements signed by Michael J. Uda and Kevin Woodruff. The Montana Consumer Counsel (MCC) petitioned to intervene on September 26, 2003. Roger Kirk petitioned to intervene on October 14, 2003. Navitas Energy Inc. (NEI), which manages Whitehall Wind LLC (WHW), petitioned for late intervention on October 31, 2003.

10. On August 18, 2003, the PSC issued an interim order, PSC Order No. 6501, granting NWE's request to adjust the QFLT-1 and STPP-1 rate schedules.

11. The settlement rates in PSC Docket No. D2002.7.80, NWE's proposed rates, and the interim-approved rates are as follows:

	D2002.7.80 Settlement Rates	D2003.7.86 Proposed Rates[3]	D2003.7.86 Interim Rates
Escalating			
Energy	4.4593¢/kwh	4.5106¢/kwh	4.5106¢/kwh
Capacity	$69.9920/kw/yr	$70.1270/kw/yr	$70.1270/kw/yr
Partially Escalating			
Energy	1.5100¢/kwh	1.5557¢/kwh	1.5557¢/kwh
Capacity	$1.718/kw/yr	$1.726/kw/yr	$1.726/kw/yr
System Lambda	1.0639¢/kwh	1.1283¢/kwh	1.1283¢/kwh

12. On September 18, 2003, the PSC issued a Notice of Additional Issues.

13. On September 22, 2003, NWE requested suspension of this proceeding, primarily based on NWE work load or other conflicts related to NWE's pending bankruptcy.

14. On October 30, 2003, by Notice of Commission Action (NCA), the PSC denied an NWE request to suspend proceedings.

15. On December 17, 2003, the PSC issued a procedural order, PSC Order No. 6501b, setting dates for pre-filed testimony and an initial hearing date.

16. On January 2, 2004, NWE filed a Motion for Reconsideration of the Procedural Order. NWE proposed a May 26, 2004, hearing date and sought to extend each milestone in the order by 90 days. On January 12, 2004, NEI responded to NWE's motion, asserting a violation of its due process rights and recommending the PSC deny NWE's Motion. On February 6, 2004, the PSC denied NWE's motion for reconsideration.

17. On January 20, 2004, NWE filed the Supplemental Testimony of Mark A. Stauffer addressing the additional issues the PSC identified on September 18, 2003. Simultaneously, NWE objected to the additional issue relating to contracts (reviewed

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[3] The escalating rates are QFLT tariff rates. System lambda is a STPP tariff rate. NWE explained it modified the STPP to coordinate with Schedule QF-1, which applies to QFs 3 MW and less in size and requires larger QFs to participate in RFPs. NWE intends to refile the QF-1 rate when it submits its prehearing memorandum. *DR PSC-075(d), but also see DR PSC-086(c)*.

below). On January 21, 2004, CELP joined in NWE's objection. On January 30, 2004, the PSC overruled, without prejudice, the objections of both NWE and CELP.

18. On February 20, 2004, Two Dot Wind, LLC (TDW) filed a petition for late intervention seeking a PSC determination that renewable energy credits (RECs) must be separately and expressly conveyed by QFs to "utilities for value." For existing QF contracts, TDW's petition seeks a determination that RECs cannot be transferred to NWE unless specifically allowed in the contract. On February 27, 2004, NWE objected to TDW's petition to intervene. On February 27, 2004, TDW replied to NWE's objection.

19. On February 23, 2004, the PSC identified RECs as an additional issue in this proceeding. The PSC provided an opportunity for interested persons to intervene for the purpose of addressing REC issues.

20. On March 17, 2004, by NCA, the PSC granted TDW's petition to intervene with respect to REC issues and established an additional issue procedure to address REC issues. On April 8, 2004, Boulder Hydro Limited Partnership petitioned to intervene on REC issues.

21. On April 15, 2004, NEI filed an objection to PSC data request (DR) PSC-053(e).

22. On April 22, 2004, WHW filed a notice of substitution of parties indicating that WHW was substituted for NEI.

23. On May 4, 2004, NWE filed an objection to DR NEI-027. On May 7, 2004, NEI responded to NWE's objection.

24. On May 11 and May 12, 2004, respectively, NWE and NEI each filed motions for a protective order.

25. On May 17, 2004, WHW requested an opportunity to file a surreply and brief in response to NWE's objection to DR NEI-027.

26. On May 18, 2004, NWE responded to NEI's objection to DR NEI-027.

27. On May 19, 2004, WHW requested continuation of the hearing.

28. On June 28, 2004, NWE made its 2004 Annual Avoided Cost Compliance filing in PSC Docket No. D2004.6.96. NWE updated rates and supporting work papers but did not raise new issues. NWE proposed to increase QFLT-1 rates, due to a higher

escalation factor, and reduce the STPP-1 rate, due to lower coal costs. NWE asked the PSC to simultaneously process the 2003 and 2004 filings.

29. On September 7, 2004, the PSC approved, on an interim basis, NWE's proposed rates effective for service on July 1, 2004. The prior interim rates, the proposed interim rates, and the approved interim rates are as follows:

	D2003.7.86	D2004.6.96	D2004.6.96
Escalating	Interim Rates	Proposed Rates	Interim Rates
Energy	4.5106¢/kwh	4.6578¢/kwh	4.6578¢/kwh
Capacity	$70.1270/kw/yr	$73.026/kw/yr	$73.026/kw/yr
Partially Escalating			
Energy	1.5557¢/kwh	1.5625¢/kwh	1.5625¢/kwh
Capacity	$1.726/kw/yr	$1.7580/kw/yr	$1.7580/kw/yr
System Lambda	1.1283¢/kwh	1.1146¢/kwh	1.1146¢/kwh

30. In an October 13, 2004, NCA the PSC consolidated PSC Docket Nos. D2003.7.86 and D2004.6.96.

31. On December 7, 2004, NWE filed a limited objection to DR WHW-011.

32. On February 17, 2005, the PSC issued a notice on discovery that also makes mention of the PSC's December 7, 2004, action suspending the procedural schedule and that, among other things, ordered NWE to provide to WHW non-proprietary information that was requested in DR WHW-011.

33. On February 23, 2005, NWE filed a response to DR WHW-011. On March 3, 2005, WHW filed a Motion to Compel Production by NWE of Actual Cost Data and Memorandum in Support. WHW asserts the non-proprietary material supplied by NWE is inadequate. On March 15, 2005, NWE filed a reply to WHW's motion. On March 17, 2005, WHW filed a reply in support of its own motion.

34. On June 13, 2005 NWE filed a Stipulation between NWE and CELP on Additional Issues 1 and 2 (discussed below).

35. On June 24, 2005, NWE made its 2005 Annual Avoided Cost Compliance filing in PSC Docket No. D2005.6.103. On July 20, 2005, the PSC, by NCA, consolidated the docket with the prior two pending QF dockets.

36. On July 20, 2005, the PSC issued PSC Order No. 6675 in PSC Docket No. D2005.6.103, approving, on an interim basis, NWE's proposed updates to the QFLT-1 and STPP-1 rate schedules. The following table summarizes the prior interim approved rates, the proposed rates, and the interim approved rates:

	D2004.6.96	D2005.6.103	D2005.6.103
Escalating	Interim Rates	Proposed Rates	Interim Rates
Energy	4.6578¢/kwh	4.2415¢/kwh	4.2415¢/kwh
Capacity	$73.026/kw/yr	$65.765/kw/yr	$65.765/kw/yr
Partially Escalating			
Energy	1.5625¢/kwh	1.5831¢/kwh	1.5831¢/kwh
Capacity	$1.7580/kw/yr	$1.7940/kw/yr	$1.7940/kw/yr
System Lambda	1.1146¢/kwh	1.1145¢/kwh	1.1145¢/kwh

37. On August 31, 2005, NWE moved to suspend consideration of all issues related to prospective QF power purchase contracts. On September 9, 2005, WHW objected to NWE's motion. On September 14, 2005, WHW and Boulder Hydro filed motions to reset the procedural schedule and to require NWE to file a motion for protective order. On September 15, 2005, NWE filed a response to WHW's objection to its August 31 motion to suspend. On September 19, 2005, WHW replied to NWE's September 15, 2005, response.

38. On September 29, 2005, NWE filed amendments to its 2004 and 2005 Annual Avoided Cost Compliance Filings which affected rates for the July 2004 to June 2005 and July 2005 to June 2006 contract years. On September 30, CELP filed motions opposing NWE's amendments to interim QF rates and requesting a hearing.

39. On October 3, 2005, the PSC, by NCA, denied NWE's motion to suspend, granted the intervenors' motions to require NWE to file a protective order and denied the intervenors' motions to reset the procedural schedule. The PSC disagreed with NWE's assessment that EPAct2005 and FERC's responsibilities under that Act warranted PSC suspension of any issue. The PSC found the issues in these dockets relate to existing as well as prospective QFs. The PSC determined that, as the dockets progress, NWE may identify specific issues and make specific arguments as to why the PSC should proceed

cautiously on those issues. In response to DR PSC-146(d), NWE identified its September 28, 2005, motion to amend as the only outstanding rate amendment request for which it continues to seek PSC approval.[4]

40. On November 16, 2005, CELP and NWE jointly moved to suspend the proceedings. On November 18, 2005, the PSC issued a Protective Order. On November 28, 2005, NWE filed a brief in support of its motion for a protective order. On December 5, 2005, WHW submitted comments on NWE's motion to reconsider special terms and conditions for a protective order. On December 6, 2005, the PSC, by NCA, denied, without prejudice, the joint motion to suspend filed by CELP and NWE. On December 14, 2005, the PSC, by NCA, denied NWE's motions for reconsideration of the denial of protective order special terms and conditions.

41. In a December 6, 2005, NCA the PSC denied the joint motion to suspend these proceedings. The denial was without prejudice.

42. In a December 14, 2005, NCA the PSC addressed NWE's motion for reconsideration of the PSC's denial of special terms and conditions in two then-recent PSC protective orders. On November 29, 2005, NWE filed a motion for reconsideration of the denial of special terms and conditions in PSC Order No. 6501d, a protective order issued November 18, 2005, in the consolidated NWE avoided cost compliance dockets identified in the above titles. For all practical purposes the PSC's denials of the NWE-requested special terms and conditions in each of the protective orders and NWE's motions for reconsideration of each of the protective orders were identical. The PSC combined the NWE motions for the purpose of ruling, determined NWE had not made a case for reconsideration and had presented no new arguments on reconsideration.

43. On February 2, 2006, the Montana Department of Natural Resources and Conservation (DNRC) petitioned to intervene.

44. On February 23, 2006, CELP moved for an interim rate adjustment based on application of an incremental cost of capital. On March 7, 2006, NWE responded to

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[4] NWE computes the amount that CELP would receive and that would be in the QFLT tariff assuming approval of NWE's amendments to interim rates. *DR PSC-146(e)*.

CELP's motion for interim rate adjustment. On March 10, 2006, CELP moved for an opportunity to file surrebuttal testimony and filed the surrebuttal of Mr. Lauckhart.

45. On March 14, 2006 the PSC issued: 1) a NSA amending the procedural schedule and setting an April 19, 2006, hearing date; 2) a NCA deferring consideration of CELP's motion for an interim rate adjustment; and 3) a NCA granting DNRC intervention. March 21, 2006, NWE filed an objection to CELP's motion to file surrebuttal testimony. On March 31, 2006, by NSA, the PSC rescheduled the hearing to begin July 12, 2006. On the same date, the PSC issued a NCA granting CELP's petition to file surrebuttal testimony, and providing NWE an opportunity to respond.

46. On June 6, 2006, CELP filed a motion to compel NWE responses to certain CELP data requests. On June 12, 2006, NWE filed an objection to CELP's motion to compel. On June 13, 2006, CELP filed a reply to NWE's objection.

47. On June 12, 2006, CELP filed a motion to exclude portions of the surrebuttal testimony of NWE witness Stauffer. On June 20, 2006, NWE replied to CELP's motion to exclude. On June 26, 2006, CELP replied to NWE's reply to CELP's motion to exclude.

48. On July 10, 2006, NWE filed an update to its response to DR CELP-026. Also on July 10, 2006, CELP filed an emergency motion to strike NWE's update. On July 12, 2006, NWE replied to CELP's emergency motion.

49. On July 12, 2006, the PSC held a public hearing in its Helena office. Prior to cross examination of witnesses and introduction of testimony and data requests into evidence, the PSC granted CELP's motion to strike NWE's supplemental response to DR CELP-026 and denied CELP's motion to exclude portions of NWE's surrebuttal testimony. Following hearing, briefs were filed on pending motions and NWE's three consolidated applications, with the last briefs filed in mid-September.

COMMISSION'S ADDITIONAL ISSUES

50. On September 18, 2003, the PSC raised the following issues on which it sought additional testimony:

Issue 1. Contract Issues: Whether the CELP contract was amended since initially consummated with NWE (f/k/a MPC) and, if so, how. The inclusion of security and liquidated damages provisions in CELP's contract with NWE.

Issue 2. STPP Issues: The analytical basis for energy and capacity rates and the merit of opportunity cost values (sales and purchases) for energy and capacity rates.

Issue 3. Long-Term Tariff for Small QFs: Whether there is merit in a long-term standard avoided cost rate option for relatively small QFs. One threshold for small is 3 MW as specified PSC rules (A.R.M. 38.5.1902(5)). A related matter is the cost/market basis for long-term energy and capacity rates. Another matter is the allowed length of long-term contracts (*e.g.*, 4 to 35 years). Whether rates should be levelized and, if so, how is another issue (*e.g.*, fully, partially levelized). The appropriate cost basis for long-term rates is of paramount interest. Options for the cost basis include but are not limited to full requirements contracts (*e.g.*, that NWE has with PPL), short- and long-term opportunity values (sales and purchase values) in markets accessible to NWE for firm and non-firm power and direct reference to recognized market prices (*e.g.*, COB or Mid-C) with appropriate transmission adjustments.

Issue 4. Technology Based Rates: Whether there is merit in separate, non-discriminatory standard rates for various qualifying small power production and cogeneration technologies.[5] Candidate technologies include hydro, wind, fossil fuels, and renewable energy fuel sources e.g., hog fuel. The analytical basis for such rates, as discussed under Issue 3 above is related to this issue.

Issue 5. Limits on QF Power Procurement: Whether it is legal and reasonable to limit the amount of QF power NWE must acquire from QFs less than 3 MWs in size under long-term or short-term tariffs.

COMMISSION'S SUPPLEMENTAL ADDITIONAL ISSUE

51. On March 17, 2004, the PSC raised a supplemental additional issue regarding RECs. This issue involves how RECs should be treated prospectively in

[5] This issue was raised during an August 21, 2003, hearing in PSC Docket D2002.6.63.

contracts between NWE and QFs, specifically which party may claim ownership of the RECs and whether any independent value associated with the RECs should be incorporated into rates paid to QFs.

TESTIMONY

52. The following pre-filed testimony was admitted into evidence in this proceeding:[6]

a) NWE Additional Issues Testimony of Mark Stauffer (NWE-1);

b) CELP Testimony of Owen Orndorff (CELP-4);

c) TDW Testimony of Van Jamison (TDW-1);

d) NWE Supplemental Additional Issue Testimony of Stauffer (NWE-2);

e) NWE Rebuttal Testimony of Stauffer (NWE-3);

f) CELP Direct Testimony of Richard Lauckhart (CELP-1);

g) WHW Direct Testimony of Robert Frantz (WHW-1);

h) NWE Rebuttal Testimony of Stauffer (NWE-4);

i) CELP Proposed Surrebuttal testimony of Lauckhart (CELP-2, CELP-3); and

j) NWE Surrebuttal testimony of Stauffer (NWE-5).

NWE Additional Issues Testimony: Mark Stauffer

53. Mark Stauffer, NWE's economist, filed testimony on January 20, 2004, addressing the PSC's five additional issues. On the first issue, he asserts that NWE has no contract-related issues that are appropriate in this docket because all rate changes in this contract were approved by the PSC.[7] He asserts NWE's 2003 compliance filing

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[6] The pre-filed direct testimony of NEI witness Christopher Moore was not entered into evidence and is not reviewed. NWE's rebuttal of that testimony is included in evidence.

[7] NWE explains that due to problems obtaining water rights and project financing CELP initiated a contract amendment that incorporates "security" into the price terms. *DR PSC-014*.

accurately reflects the appropriate method for computing QFLT-1 rates for all contracts, including ones that, like CELP's, reference the QFLT-1 rates.[8]

54. As for the second issue, Stauffer recommends closing the STPP rate to new offerings.[9] He adds that computation of the STPP rate is consistent with how the rate is currently used and should not be altered. He asserts the rate is limited to specific QFs and for power in excess of firm obligations and, as such, it is for non-firm power.[10] He

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[8] NWE's contracts with CELP, Jenni Hydro, and Pine Creek reference QFLT-1 rates to change the adjusting portion of the payment under these contracts. *DR PSC-003(a)*. NWE explains that when CELP is unavailable to provide power, due to "unplanned outages," capacity payments in the next year are adjusted and excess energy is paid a "negotiated rate." *DR PSC -015(a),(d)*.

[9] NWE explains its understanding of the basis for the STPP rate in DR PSC-005. NWE provides a table with historical STPP rates in DR PSC-004(c). If the STPP is not closed and remains based on PSC orders in PSC Dockets No. 81.2.15 and D83.1.2, NWE estimates an energy rate of $11.283/MWh and a capacity rate of $4.709/MWh. NWE estimates most of its opportunity sales are made in the Mid-C market. *DR PSC-006*.

NWE asserts the Pacific Northwest (PNW) power market is dysfunctional with considerable price instability so use of regional power markets as a source of opportunity costs for a five year proxy rate would be extremely speculative. *PSC -007(a)*. NWE asserts it filed an estimate of the regional market value for firm power in its tracker PSC Docket D2003.8.115 but it does not have non-firm power prices. *DR PSC-007(c)*. NWE asserts it would turn to the "market" for incremental purchases, at costs contained in its tracker citation, if it had inadequate supplies of energy and capacity in the 2004 to 2008 time period. NWE adds that large resources developed in Montana compete in the dysfunctional PNW wholesale market. Besides the Mid-C market, NWE asserts numerous utilities in the region conduct RFPs open to any producers and, therefore, "large" QFs have numerous opportunities in the competitive PNW market. *DR NEI-013*. NWE proposed to discontinue the STPP rate because system lambda, on which the rate is based, reflects avoidable incremental dispatch costs and NWE disfavors changing the basis of the STPP rate. *DR PSC-018*.

[10] NWE advocates using the STPP rate for existing contracts involving non-firm power. *DR PSC-065(a)*. NWE explains that Pony Generating Station uses the STPP for volumes in excess of 300/kw/hour and that South Dry Creek and Strawberry Creek have defaulted to STPP rates "under expiration of response time in a contract termination." *DR PSC-003(b)*. NWE asserts prior PSC orders directing the STPP to include energy and capacity payments do not apply to CELP's excess energy production, which is a negotiated rate. *DR PSC-015*. NWE admits no supplier of energy offers a price of

suggests a capacity payment unwarranted because NWE cannot rely on the power being available to serve loads.[11] He states that NWE can only "resell the power after incurring transmission and administrative expenses." *NWE-1, p. 3.* He proposes that NWE would update the rate in the manner proposed in its 2003 compliance filing *(PSC Docket No. D2003.7.86, the first of the three consolidated dockets in this order)* until the rate is not used.[12]

55. As for the third issue, Stauffer testifies that the availability of the QF-1 tariff rate should continue, with updates after future NWE requests for proposals (RFPs).[13] Given the dynamic nature of the NWE supply portfolio and the PURPA requirement for accurate avoided costs, he recommends updates at least annually. He recommends continuing the present method of tying the "single" rate to the weighted average cost of non-QF resources in NWE's portfolio. He favors contract terms of 5 years or less for

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$.011283 (the contract year STPP rate) except for QFs from whom it is required to buy sporadic non-firm energy on a long-term contract basis. NWE adds it does not intend to purchase energy that has no value to firm load customers. *DR PSC-016.*

[11] NWE provided $94.71/kwh/yr (sic) as the annual capacity cost for a combustion turbine. *DR PSC-003(e).*

[12] NWE's June 30, 2003 compliance filing used a full year of invoices for coal costs, inflated to current year dollars, holding this is a fair and sustainable method of computing coal costs consistent with PSC Order No. 5017, Docket No. 83.1.2. NWE adds the proposed rates have increased relative to the settlement rates, due primarily to the increased cost of coal and to escalation factor increases. The filing also proposed to modify the applicability of the STPP-1 to coordinate with the QF-1 rate schedule. Since the QF-1 applies to QFs with an installed capacity of 3 MWs or less the STPP must be modified "to address QF projects" greater than 3 MWs that deliver power between solicitations.

[13] NWE explains that the QF-1 rate for the 2003/2004 contract year was based on a contract with Duke Energy because it was the best indicator of the market value of QFs since it was a unit contingent power from Colstrip No. 3 and No. 4. *DR PSC-018*. NWE explains that the contract rate and length would be based on specific "marginal RFP contracts." Once a QF signs a contract, the rate and the contract length is fixed; if NWE is "forced" into contracts longer than the avoidable length associated with the cost, then the contract rate should be revised each time there is an addition to the "RFP." *DR PSC-080(a).*

large QFs.[14] He also favors limiting the quantity and terms of smaller QF projects and requiring larger QFs to participate in RFPs.[15] In this regard, he advises the PSC to be cautious so as not to "repeat QF events of the past" that might result in new stranded costs. Due to the likelihood of new federal legislation amending PURPA to have a more "market-based prospective (sic)," and if need exists in its load/resource balance, NWE proposes to make the QF-1 available to QFs larger than 3 MWs on a temporary, "between RFP," basis, but for no longer than 5 years.[16] *NWE-1, p. 4.* Thus, if the STPP is eliminated, the QF-1 would be available to all large QFs until contracts are awarded at

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[14] NWE explains that the theoretic basis for the QF-1 rate is the cost that NWE would otherwise pay for power if it did not acquire power from the QF. NWE's proposed QF-1 rate is based upon the weighted average rate paid to wholesale suppliers for firm power, including payments for energy and capacity, and therefore reflects "market based marginal costs." *DR PSC-008*. NWE explains that the proposed rate in DR PSC-008(e) reflects PSC Order No. 4865, FOF 31, which states "a separate annualized capacity payment based on the costs of a combustion turbine paid in proportion to an 85% availability factor is to be developed." *DR PSC-013*. NWE explains how the QF-1 rate includes Basin Creek costs. *DR PSC-141(a)*. Assuming the weighted average cost of its most recently completed RFP process reflects the most economical power available, NWE asserts it provides a good approximation of what would otherwise be acquired and is, therefore, avoided cost based. *DR PSC-013(b)*. NWE does not believe it is appropriate to use the regional spot market as a source for the marginal cost of capacity. *DR PSC-013(c)*. NWE adds that because QF contract rates are not part of the calculation there is no circularity in a weighted average rate. *DR PSC -080(c)*. NWE provides some of the resources and rates that would be in the weighted average rate. *DR PSC -066(a)*. NWE proposes to "allocate" the weighted average rate to demand and energy (diurnal). *DR PSC-081(a)*. NWE adds that the term of QF contracts is an issue as significant as price and quantity. *DR NEI-022*. NWE explains long-term contracts offer less flexibility to respond to changes in market prices and therefore pose more risk for stranded costs. *DR NEI-011*. NWE opposes including opportunity sales in QF rates. *DR PSC-066(b)*.

[15] NWE held that a QF's size should be a function of a complete project at a particular site. If machines were located at the same site, the size would be the sum of the installed capacity of all machines. *DR PSC-082(a)*.

[16] NWE explains that "need" means a positive difference between expected load less the contracted resources available to serve that load. *DR PSC-012(e)*.

the conclusion of an RFP.[17] If a large QF is not awarded a contract, it must wait until the next RFP. Stauffer refers to the fourth issue (discussed below) for a further discussion of his position on long-term contracts.

56. As for the fourth issue, involving non-discriminatory technology based rates, Stauffer holds that if the PSC adopts NWE's proposal to offer the QF-1 rate on a 5-year or less basis to large QFs, then it is necessary to "break" the rate into capacity and energy components.[18] He proposed a capacity price reflective of the annual capital cost of a combustion turbine (CT). The energy rate would be the remainder, or the total rate less the CT cost.[19] He also proposed a technology adjustment to the capacity rate. The result is that the annual capacity rate would be adjusted by the QF's capacity factor relative to the portfolio's capacity factor.

57. As for the fifth additional issue, limiting the acquired QF power, Stauffer referred to his response to the third issue and his attached Exhibits MAS-2 and MAS-3.

<u>Colstrip Energy Limited Partnership (CELP) Testimony: Owen Orndorff</u>

58. On March 4, 2004, CELP filed the testimony of Owen Orndorff. Orndorff addressed the PSC's first additional issue involving CELP's contract. He explains why CELP disagreed with the PSC for having raised the issue. He understands the issue to be one of why the security and liquidated damage provisions, in the original (unamended

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[17] NWE explains the QF-1 rate computation in DR PSC-086(c) and DR PSC-141.

[18] NWE proposed dividing the rate into energy and capacity to reflect the two distinct market products and to incent producers to provide energy when it is most valuable, and in addition, to maintain consistency with PSC orders in PSC Dockets No. 83.1.2 and 84.10.64. *DR NEI-016*. NWE adds that it is fair to adjust capacity to account for intermittent resources such as wind. *DR NEI-019*.

[19] Based on a Northwest Power and Conservation Council (NWPCC) paper and existing market prices for natural gas, NWE estimates an energy cost for a combustion turbine of about $57.10/MWh ($40.17/MWh if the price of natural gas were $3.25/mmbtu). NWE did not provide estimates of costs for the related energy and capacity from the Basin facility. *DR PSC-010*. NWE explains that the combustion turbine capacity cost stems from PSC orders in PSC Docket No. 81.2.15. *DR NEI-016*.

agreement) CELP/MPC Power Purchase Agreement (agreement), were eliminated. Given prior PSC decisions on its jurisdiction over such matters, he holds that the PSC has incorrectly raised this issue. He said the PSC's inquiry is improper because there is no active dispute. He adds that with the PSC's present view, a party need only trigger a contract or amendment controversy to remove a matter from PSC purview. However, he asserts the PSC's interpretation of its authority is improper because the courts have concluded the PSC does not have jurisdiction over executed contracts. Further, the PSC's consideration of this issue raises the sort of controversy over the meaning of contract terms that the PSC is advised would strip it of jurisdiction. Because of the importance of the agreement to CELP, involving significant underpayments to CELP from "published PURPA rates" made by NWE/MPC since 1990, any attempt to void the amendment would result in "significant additional payments to CELP," and may adversely impact NWE's bankruptcy reorganization effort. *CELP-4, pp. 3-5.*

59. Orndorff next explains why the first amendment was executed, including the change in rates. After executing the agreement in 1984, CELP (AEM at that time) concluded that the "liquidated damages" provision made financing impossible. CELP accepted a resolution developed by MPC (now NWE) that reduced payments in early contract years to levels not requiring security and involved getting "acceptable assurance from the Commission" that the change would not be a "material" change to the agreement. In 1988, assurance was received in the form of PSC (staff level) guidance that the agreement would be amended to "delevelize" rates but with guaranteed escalation for the first 15 contract years. As a result, in place of the first year partially levelized energy and capacity rates (3.751¢/kwh and $91.54/kw/yr, respectively) CELP's rates began at 2.222¢/kwh and $55.94/kw/yr. *DR PSC-020(b)*. The PSC authorized the recovery of CELP's reduced rates in numerous QFLT rate filings including PSC Docket No. 91.6.24. He notes that NWE confirmed the existence of the first amendment to the PSC and that NWE assured CELP of the validity of the first amendment. Further assurance of the first amendment's validity was provided by NWE. CELP has included

the amendment in filings with the PSC, including in PSC Docket No. 91.4.15. Rate approvals each year since 1990 have been based upon reduced rates in the first amendment. Orndorff adds that the PSC never approved the terms of the 1984 AEM-MPC agreement. *CELP-4, pp. 6-8*.

60. Orndorff also addressed the savings associated with the amended agreement. He estimates that ratepayers saved over $57 million, from "published QF rates" available to CELP.[20] *CELP-4, p. 8*. He testified that although the first amendment freed NWE from any refund obligation and freed CELP from any security fund obligation, this does not mean that NWE would not have a $57 million obligation under the first amendment if it terminated the agreement. If CELP had received levelized payments from day one, it would have been overpaid in the early years and the amount escrowed by means of the security fund obligation in the case that CELP did not perform for the contract term. If CELP had received the levelized payment stream and performed, then NWE must refund the security funds. *CELP-4, p. 9*. As ratepayers benefited in the early years, for CELP to remain "whole" it must receive the over payments in the "out years." *Id., pp. 8-9*.

61. Orndorff also testified on the "out of market payments" for QFs that are contained in the stipulation approved by the PSC in PSC Docket No. D97.7.90. He notes that NWE used contract payments based upon the first amendment's rates to compute $663 million in out-of-market QF costs**.** *CELP-4, p. 10*.

62. In contrast to NWE's response to PSC data requests, Orndorff held that the above testimony is much more accurate. He made three comments about NWE's responses. *See CELP-4, pp. 10-12*. First, he finds that NWE's response to DR PSC-014(b) was inaccurate, as the CELP amendment was, in part, needed to acquire water rights and to obtain financing. *Id., p. 10*.

63. Second, in regard to DR PSC-015(d), whereas NWE suggested that energy production in excess of the 306,600 MWh/year maximum would be paid a negotiated rate he notes that, notwithstanding a court order, no negotiations occurred. He provides a

[20] Because in the early years revenues were reduced by $57 million CELP is required to have higher rates in later years. *DR PSC-019(a)*.

letter sent to NWE in which CELP did agree to “market pricing.” The most appropriate basis for market prices would be Mid-C rates plus the BPA wheeling and line losses to NWE’s service area although the price that NWE would avoid should be the market price that CELP receives. *DR PSC-021(b)*. However, CELP has no opinion on what the relationship should be between STPP and QFLT, as the spot market price for power is not sufficient to obtain equity or debt financing. Long term fixed rates are essential. *DR PSC-022*.[21]

64. Third, in regard to DR PSC-017, Orndorff disagrees with NWE’s estimate (in PSC Docket No. D97.7.90) of $1.23 billion in out-of-market QF costs. *CELP-4, pp. 11-12*. He disagrees because the estimate ran from 1998 to 2032 and is based, in part, upon assumed market prices of 2.225¢/kwh. This assumption is not historically accurate nor does it reflect actual market costs for long-term resources which would be required in the portfolio to replace QF contracts. It is historically inaccurate as the market costs from 1998 to 2002 were enormously higher. At a minimum, the NWE attachment, “WAP-E” provided in a data response DR PSC-017(a) should be updated for actual market prices from 1998-2004 to determine if the QF contracts are out of market.[22] With an appropriate update, pricing should reflect the replacement cost of a long-term resource. It should reflect the replacement cost because 2.225¢/kwh is an artificially low price

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[21] NEI asserts NWE did not incorporate the value of existing QFs at times when they provided energy at substantial discounts to the market. *DR PSC –032(d)*.

[22] The request and NWE’s response to DR PSC-017(a) are as follows:

Request: First, please describe the specific basis for “out of market” costs that was the basis of MPC’s estimate(s) in D97.7.90. The description must explain how MPC estimated its alternative cost and it must describe what the basis was of the alternative cost estimate that MPC supported. Did, for example, the estimate use: 1) “opportunity costs,” 2) regional energy and capacity costs, or 3) some other source for alternative costs that enabled it to conclude that the QF contract prices were out of market.

Response: The out of market costs are the difference between the expected QF costs and the market value of the power. The market forecast was based on three components. From 1998 to 2002 the price is based on the PPL MT buyback rate, from 2002 to 2007 the price was based on responses to NWE’s RFP for baseload power from its Default Supply Portfolio (specifically the Duke contract), and from 2007 on the price offered by the buyer in a generation sale and is not a market price by which QF contract values should be measured. He adds that comparing actual market pricing for new equivalent resources is the only means to access an ever changing out-of-market analysis as market pricing changes every year over the term of any QF contract. *CELP-4, pp. 11-12*. He suggests that long-term forecasts of market prices are inaccurate, as the only assurance that anyone can offer with a long-term forecast to 2032 is that such a forecast will be wrong.

65. As for NWE's January 2004 Electric Default Supply Plan (Plan), Orndorff mentions that NWE may seek to renegotiate or reject, in bankruptcy, its QF contracts. In response, he testified that neither Yellowstone Energy Limited Partnership (YELP) nor CELP will willingly renegotiate their existing contracts which would reduce cash flow and jeopardize lender/partner approval. He adds that given the bankruptcy of YELP's own contractor, YELP itself is in precarious financial health.

66. Orndorff does not believe that NWE could successfully reject the existing QF contracts. Even though the test to approve contract rejection is the "business judgment" test, courts will also consider if rejection might have a disproportionate, large, and harmful impact on the non-debtor contract party. He testified that NWE is unlikely to meet the test for 3 reasons: 1) it will not likely benefit the estate; 2) damage claims may dilute creditor recoveries; and 3) the likely impact on NWE's rates would not enhance its reorganized value. In addition, NWE's obligation to purchase from QFs resulted from compliance with state laws *(e.g., § 69-3-601, MCA)* and PSC orders.

67. Orndorff testified that QF contract rejection will impact NWE's consumer rates as any out-of-market value that NWE alleges (in response to DR PSC-017) will become an additional significant unsecured creditor claim. The suggested $1.23 billion out-of-market pricing would severely impact the existing $1.8 billion of unsecured creditors' total recoveries and likely jeopardize the approval of any plan of reorganization absent a rate increase to make unsecured creditors indifferent to including the QF unsecured creditor claims. *CELP-4, p. 14*. Although NWE's position is that any contract

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was increased at the projected rate of inflation. Further information is available from the rejection will reduce annual ratepayer payments for QF resources by $25 million, Orndorff adds that the PSC and NWE did not agree to reduce stipulated payments to NWE for the loss of QF resources; thus, the worst outcome for ratepayers and the best outcome for NWE's creditors/shareholders would be for NWE to collect the annual $25 million and eliminate and replace all QF resources with, for example, a new rate, one that is based upon a NWE gas project. *CELP-4, pp. 13-14*.

68. Based on an analysis of market pricing for new long-term resources, Orndorff concludes that YELP and CELP are not out-of-market resources. His analysis assumed that QF contracts, even if rejected, remain a ratepayer cost and that no long-term resource can be built for less than $.05/kwh.[23] He adds that a project cannot achieve lender financing absent "a minimum 1.5 debt service coverage after project operating expenses" (debt service requires payment of both interest and principal). He testifies that NWE has consistently made less than full payments required under existing contracts. He also testified that CELP, YELP, and another QF have brought lawsuits in the Delaware court and noted that unless NWE corrected its commercial behavior with independent energy suppliers that such "conduct" will further frustrate financing and will result in arguments by NWE that it must build its own project. *CELP-4, p. 15*.

69. Orndorff recommends that QF contracts be "promptly assumed" as there is no viable alternative to acquire cheaper resources without impacting the reorganization.[24] As delay will only result in a weaker successor company and higher ratepayer costs, NWE's filed plan should be reviewed and implemented as soon as practicable if NWE is to remain a "separate entity." *CELP-4, pp. 15-16*.

D97.7.90 record.

[23] Orndorff's $.05/kwh estimate is based on project development experience in Montana. Only a fixed price, not a fluctuating market price, will provide the necessary assurances for debt service and equity returns. *DR PSC-026*.

[24] By "promptly assumed," CELP means that the "Plan of Reorganization" must necessarily deal with the treatment of executory contracts and "Assumption simply means executory contracts in existence prior to the bankruptcy proceeding should continue after the reorganization of NWE as if the bankruptcy did not occur." *DR PSC-027*.

Two Dot Wind, LLC, Testimony: Van Jamison

70. On March 4, 2004, Van Jamison filed testimony on behalf of Two Dot Wind, LLC (TDW). His testimony focused on the treatment of renewable energy credits (RECs) in transactions between a utility and a QF.

71. Jamison explains the absence of an established standard for defining RECs, also referred to as either green tags or renewable energy certificates. Generally, he says, that a REC "is a collection of all environmental and social attributes internalized in a unit of only 'renewable' generation which has been separated from the underlying electricity product to be sold independently as a discrete, tradable instrument." [25] The concept of RECs is meaningless in the context of power markets. However, within power markets products that include all the attributes underlying RECs may also be purchased and sold as "green power."[26] Green power is often marketed as a distinct, higher-value power product.

72. Jamison highlights what he sees as an inconsistency in the way NWE offers its optional E+ green power service to retail customers and the way that NWE approaches negotiations with renewable QFs. NWE's E+ green program allows customers who want to support new renewable energy resources to pay a premium of $2.00 per month for each 100 kwh block of renewable energy attributes ($20/MWh) in addition to all other electricity supply and delivery charges. Each $2.00 premium buys the environmental benefits associated with 100 kwh of renewable energy being generated in the northwest and Wyoming. Jamison asserts a fundamental purpose of RECs is to give renewable energy project developers a co-product to sell in addition to power, thereby encouraging

[25] "Attributes," as used in defining RECs, means environmental and social benefits that exceed established minimum environmental and social standards, permitting, and other requirements. These additional benefits are the basis of a REC's value. *DR PSC-054(b)*. The primary attributes embodied within RECs are related to air quality, water quality, and waste reduction advantages that renewable resources have compared to other types of generation. *DR PSC-055*.

them to build additional projects. According to Jamison, at the same time NWE is asking retail customers to pay a premium to support renewable projects, it is trying to obtain RECs from renewable QFs without compensation at its avoided cost. Jamison asserts this asymmetric treatment of "green" values distorts and compromises power markets.

73. Jamison criticized NWE for ignoring the price signals being conveyed through green power products and RECs, given that the company has specifically accounted for other material differences in the power products QFs provide, such as capacity factors. However, he does not recommend requiring NWE to pay a higher avoided cost rate to renewable QFs to account for the price signals conveyed in green power markets and markets for RECs. Rather, NWE should be free to decide whether or not it wants to buy the renewable attributes from renewable QFs. NWE should not be allowed to refuse to enter an agreement with a renewable QF unless the QF "hands over" the RECs without compensation. Jamison suggests proper compensation for renewable attributes could be in the range of $4.00 to $7.00/MWh.

74. Jamison acknowledges that given the immature nature of REC markets it is difficult to track the trading and use of RECs.[27] There are not consistent standards for what is renewable and, therefore, what RECs represent. Because tracking systems are not well developed, double counting plagues the system. However, numerous groups are working to address these market design issues, including a work group under the Western Governor's Association.

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[26] whether renewable electricity supplies are purchased as bundled "green power" or RECs are purchased separately and combined with non-renewable electricity products, the resulting product is "green" or renewable. *DR PSC -055(d)*.

[27] Presently there is no organized marketplace where RECs or their equivalents are traded within the Western Electricity Coordinating Council boundaries, although many marketers offer "green power," RECs, and other renewable energy products. *DR PSC-054(d)*. Markets for standard power products such as energy, capacity, and ancillary services are more developed, in part because these markets are more broadly regulated. *DR PSC-058*. Jamison declined to answer the question of whether any state or federal laws or rules would preclude a prospective QF from obtaining QF designation if it had previously sold its RECs.

75. Ultimately, Jamison recommends that the PSC determine that resource attributes associated with a QF belong to the QF and any exchange involving those attributes should be separate transactions not covered within PSC-approved avoided cost tariffs.[28] He also recommends that the PSC determine that NWE only obtains title to energy and capacity purchased pursuant to QF tariffs.[29]

NWE Supplemental Additional Issue Testimony: Mark Stauffer

76. On March 31, 2004, Stauffer filed supplemental testimony addressing REC issues. He submitted his supplemental testimony after NEI and TDW prefiled testimony on this issue. He considers RECs separate products, distinguishable from power purchased through QF contracts or contracts that result from competitive solicitations. In general, he agrees with the way Jamison characterized RECs (see summary of TDW testimony above). He asserts the following in his testimony: 1) the market for RECs in the Pacific Northwest is in its infancy; 2) distribution utilities will be the primary intermediary between renewable energy generators and retail consumers who want to buy renewable energy; 3) the disposition of RECs associated with renewable QF projects should be determined by negotiation between willing buyers and willing sellers; and 4) the avoided cost for power and the market value of RECs should be kept separate because PURPA does not require utilities to purchase RECs.[30]

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[28] When asked how a QF would market its resource attributes, Jamison stated such attributes could be sold to brokers or marketers who would in turn resell them. He added that a QF could auction RECs or contact known REC traders. *DR PSC-058*.

[29] Jamison stated that RECs are a commodity separate from the QF-related issued of avoided cost. The PSC should recognize that RECs rightly belong to the project owner until they are voluntarily sold. *DR PSC-054*.

[30] Stauffer agrees PURPA explicitly constrains would-be QFs to electricity production methods that either represent an improvement in thermal efficiency compared to conventional generation or embody renewable resource attributes. However, he maintained that a QF wind project is a renewable resource with or without RECs. If NWE were required to disclose the fuel source and emissions information related to its

77. While there is not a mature market for RECs, Stauffer believes an efficient market will develop and provide incentives for renewable energy product development. He adds NWE currently participates in REC markets.[31] He asserts utilities need flexibility to decide how many RECs to acquire and at what price based on retail customer demand. He asserts NWE and a renewable QF should mutually agree on an exchange of RECs before a transaction occurs. He also asserts the avoided cost rate should not be adjusted when NWE purchases a green power product from a QF. Instead, a value for the renewable attributes would be determined separately between the two parties.

78. Stauffer favors trading RECs in the marketplace for several reasons. First, he says PURPA does not require utilities to purchase RECs; PURPA requires utilities to purchase power from a QF at a rate that is equal to what the utility would otherwise pay for that power. Since a particular QF project may or may not separately produce RECs, he reasons avoided costs should be unaffected by RECs. Second, he asserts the market will establish equilibrium and prevent distortions in the supply of and demand for RECs. Third, he says NWE does not know how many RECs it will need to supply the demands of its customers, which, in turn, is a function of the price NWE charges, with PSC approval, for products offered under the E+ green program.

79. Stauffer rebuts Jamison's assertion that NWE tries to coerce renewable QFs into transferring environmental benefits to NWE without compensation. He maintains NWE does not require QFs to transfer RECs to NWE as a condition of any power purchase agreement. Rather, NWE inserts language in proposed contracts with QFs that define the disposition of RECs as a starting point for negotiations; it is essential, he says, for any business relationship involving a renewable QF to be clear about which party has rights to RECs.

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resource portfolio, NWE would disclose the renewable attributes of a renewable QF even if the QF sold RECs to another party. *DR PSC-052*.

[31] NWE purchases RECs from Bonneville Environmental Foundation in order to obtain the renewable attributes sold to retail customers through the E+ green program.

80. Stauffer disagrees with Jamison that NWE misleads its E+ green customers by coercing RECs from QFs and reselling them to customers for $20/MWh. He says NWE does not obtain any RECs from QFs. NWE purchases RECs to support the E+ green program from Bonneville Environmental Foundation and incremental revenues NWE receives above the purchase costs are used to promote the program.

NWE Rebuttal Testimony: Mark Stauffer

81. On April 15, 2004, NWE filed the Rebuttal Testimony of Mark Stauffer responding to the testimony of NEI witness Moore. Stauffer first identifies two issues on which he and Moore disagree. These issues involve QF access to the QF-1 rate and the appropriate length of standard contracts. First, while Moore held that large QFs should have access to the QF-1 tariff, Stauffer agrees to such access only until NWE completes its next RFP. Second, Moore supported contract lengths of at least 15 years, while Stauffer asserted, based on ratepayer indifference, that contract lengths should reflect the weighted average length of the underlying contracts that are the basis of the rate.[32] *NWE-3, pp. 1-2.*

82. Stauffer elaborates on these two issues. He asserts QFs have adequate access to regional power markets, as evident from Idaho Power Company's recent purchase of 9 MWs of wind in Great Falls and Avista's recent purchase of 35 MWs of wind.[33] Further, he asserts all large transmission providers have open access tariffs. Still, he says NWE would pay large QFs the QF-1 rate until the next RFP is complete. If a

[32] NWE asserts its proposal to use the weighted average of marginal contracts (*e.g.*, baseload, peaking), not embedded contracts, maintains the intent of marginal, or avoided, costs. *DR PSC-080(d)*.

[33] NEI is resistant to basing avoided cost rates on any market value absent a hedge mechanism because of the volatility of market indices and because market rates do not reflect long-term marginal costs. *DR PSC-032(c) and DR PSC-037(d)*. NEI asserts avoided costs should reflect the opportunity cost principle. *DR PSC-033(a)*. NWE asserts energy traded in Montana reflects a $3/MWh discount to Mid-C index prices due to transmission costs and in order to account for the sharing of transmission cost avoidance. *DR PSC-087(c)*.

large QF is not selected in the next RFP, it would not be eligible for subsequent QF-1 payments but could submit a bid in any future RFP. He asserts continuing to pay a large QF the QF-1 rates if it fails to secure a contract through an RFP would undermine the competitive process, violate avoided cost rules, and burden ratepayers.[34] *NWE-3, pp. 2-3*. It would burden ratepayers because a QF that knew it could always receive the QF-1 rate would displace RFP bidders by taking the rate. As a result, any incentive to participate in the RFP is removed. If the QF participated, it would have an incentive to bid high because of the QF-1 safeguard. Both reasons point to how the efficiency of the competitive RFP process would be compromised. *NWE-3, p. 3*.

83. Stauffer asserts there is no evidence that the current 3 MW limit on the availability of the QF-1 tariff is irrational. He adds large QFs are capable of negotiating with numerous potential buyers and do not need the same access to the QF-1 tariff as small QFs.[35] Both scale economies and open transmission access provide large QFs the ability to compete effectively in regional RFPs. *NWE-3, pp. 3-4*.

84. Stauffer maintains his basis for avoided cost rates is rational. He asserts NWE, as the Default Supply Utility (DSU), is 100 percent reliant on markets for all "marginal purchases" and these purchases are the basis for avoided costs. *NWE-3, p. 5*. He asserts that because NWE's avoided cost rate relies on marginal purchases, it no longer relies on "system lambda," utility built resources, or theoretical resources.[36] Nor does it rely on what Moore labeled a "market hedge value," which Stauffer correlates

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[34] With regard to violating avoided cost rules, NWE notes consumer indifference would be violated if an inefficient RFP process produced avoided cost rates higher than they otherwise would be. *DR PSC-068*.

[35] NWE elaborates on the demarcation between large and small QFs and why small QFs may not have access to regional power markets in DR PSC-066(e).

[36] NWE admits the basis for the STPP rate is system lambda and a capacity payment. *DR PSC-071*. While the interim STPP rate is $.01128/kwh, NWE admits the cost of its short-term transactions amounted to $.032137/kwh. *DR PSC-084(c)*.

with "opportunity sales."[37] He finds "potential opportunity sales," especially Moore's suggestion to pay QFs the higher of the avoided cost rate or the market, irrelevant to the avoided cost rate calculation.[38] He asserts Moore's proposal is "opportunistic" because credit for any excess power that is sold in the market would go to the QF, not ratepayers. If a QF wants to speculate, it should not sell power to NWE. Stauffer asserts NWE tries to avoid risk associated with spot market volatility and would not sign a contract with the provision suggested by Moore. *NWE-3, pp. 5-6.*

85. Stauffer explains that when NWE purchases QF power in excess of its DSL obligation it may be appropriate for the rate to deviate from the QF-1 rate. If a QF demands a contract when NWE is in resource balance, then the QF should receive the QF rate only for power used for DSL consumption. If the power provided exceeds NWE's needs, the QF should be paid the lower of the QF rate or the market rate. *NWE-3, pp. 6-7*. He adds that to fulfill its DSU obligation NWE must be able to rely on power providers.

86. Stauffer asserts requiring NWE to purchase long-term power in excess of its DSL needs is bad public policy and would violate the fundamental premise of PURPA, ratepayer indifference. Further, such a requirement would transfer risk from QFs to NWE and its ratepayers and potentially create "stranded costs." In cases of excess supply the appropriate QF-1 rate is zero because there is no value to the DSU in buying long-term power to, in turn, resell it. He reiterates that "large QFs" have "equal access" to the same markets as NWE and at equal transmission costs. In this regard, only those QFs

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[37] NWE finds opportunistic Moore's proposal to pay QFs the higher of the spot market or the avoided long-term contract. *DR PSC-071(c).*

[38] NWE explains it has supply contracts involving market purchases with terms from one hour to 90 days. *DR NEI-004(a) and DR PSC-032(c).* NWE does not believe opportunity sales values belong in the QF rate. QFs can market their own power, up to 8760kwh/kw per year, at a cost of $40.88/kw/yr for point-to-point transmission and if transmission capacity is available. If QFs wish to reach markets beyond the entities with which NWE has interconnection (BPA, IPC, Avista, WAPA, and PacifiCorp), then they may incur additional transmission costs. QFs have the same opportunities to make sales in the regional markets in which NWE has sales opportunities. *DR PSC-067.*

"that NWE is forced to acquire" and that are in excess of need would be "on the margin." QFs that allow NWE to avoid other purchases should receive the QF-1 rate.

87. Stauffer asserts that the contract costs he proposes to use in computing the QF-1 rates are the most recent marginal contracts. These contracts will be updated once NWE completes its current RFP. He says the old QF contracts contain no useful avoided cost information, as they were administratively determined and, unfortunately, reflect rates that are severely divorced from any reasonable market value.

88. Stauffer maintains his method of computing QF-1 rates reflects NWE's unique DSU structure. He asserts NWE is not competing to serve its DSL.[39] Instead, NWE seeks competitors to submit bids to serve that load. PURPA's original purpose was to allow QFs an equal opportunity, relative to the "native utility," to serve loads. He maintains the RFP process provides large QFs an equal opportunity along with all other providers to serve NWE's loads. The QF-1 rate represents a second opportunity for large QFs that other suppliers don't have, *i.e.*, QF-1 payments until the next RFP. He says this opportunity more than meets PURPA's requirements. *NWE-3, p. 8.*

89. Stauffer testifies that NWE is rebuilding its default supply portfolio with new contracts to replace existing contracts. NWE expects to issue RFPs seeking bids for dispatchable, base load and post-2007 replacement power. Until this RFP is complete and NWE has had an opportunity to analyze the proposals and compute a new QF-1 rate, Stauffer proposed QF rates based on the most recent contracts in the existing portfolio. He adds NEI can bid in the RFP.

90. In rebutting Moore's testimony Stauffer defends his use of a combustion turbine to "differentiate" the total QF rate into energy and capacity. He asserts that CTs are used regularly by the industry for this purpose and that the approach is a corollary to the PSC's Base-Peak method.[40] He explains his use of an 85 percent capacity factor to

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[39] NWE admits that § 210 of PURPA is not limited to vertically integrated utilities. *DR PSC-074.*

[40] NWE explains PSC Order No. 4865, FOF 31, supports the view that its proposal is a corollary to the base-peak method. In its current application, NWE substitutes the "total

spread the capacity charge over the load served. He asserts this is necessary because DSU customers are all firm energy customers and should therefore pay a portion of the capacity charge.

91. Stauffer asserts seasonal and diurnal allocations are needed in addition to separate capacity and energy rates.[41] Since NWE is not vertically integrated, traditional "loss of load" analysis is not available for this purpose. NWE hopes responses to its RFP will provide data useful for allocating "new QF-1" rates between capacity and energy as well as to diurnal and seasonal time periods. *NWE-3, p. 10.*

92. In rebutting Moore, Stauffer asserts intermittent resource providers have no interest in capacity rate components. He notes capacity is essential to serving load and provides energy at the time it is contracted for. Since wind power cannot guarantee such energy, Stauffer says he is not surprised that NEI finds capacity an irrelevant product. He asserts that allocating the total rate diurnally and seasonally without differentiating between energy and capacity, as Moore proposed, would effectively pay NEI for firm capacity it does not provide. NWE must know how much capacity it has available to serve its load. NWE acquires capacity through contracts. Therefore, Stauffer concludes, the QF-1 tariff must have a capacity rate to accurately reflect this product. *NWE-3, p. 11.* Under Stauffer's tariff proposal, QFs must contract to provide an amount of capacity at

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market costs" for base load coal unit costs. NWE adds that its attachment to DR PSC-008(e) is the implementation of "Order 5017 base/peak rates." *DR PSC -074(e)*. NWE explains the corollary has no mathematical connect to the underpinning base-peak approach but is simply a matter of logic. *DR PSC-086(a)*. NWE adds, "Since the total market price replaces the total base load costs, and the supplied NPCC costs replace the peaker costs, the basic base/peak approach is retained with all costs included, but significantly simplified." NWE advocated the exclusion of peaker running costs on grounds that in most years the region has better than average water conditions. *DR PSC-086(b)*.

[41] NWE explains its RFP was not intended to yield information that would allow for "allocating" the QF-1 rate between energy and capacity. NWE adds that because QF power production is metered on an hourly basis capacity rates may vary on a diurnal or seasonal basis. *DR PSC-076*. NWE intends to view each QF on an individual basis and does not appear to recognize an aggregate capacity value for multiple QFs. *DR PSC-077*.

"agreed time intervals." If they fail to provide the capacity, NWE will not pay them for it, since NWE must then pay someone else for capacity.

93. Stauffer rebuts Moore's assertion that the Northwest Power and Conservation Council's (NWPCC) CT cost estimates are "wildly inaccurate." Since NWE is not planning to develop resources Stauffer says he relies on reputable sources, such as the NWPCC, for proxy numbers. He finds the NWPCC's 2004 estimate more accurate than Moore's 1994 estimate. *NWE-3, p. 10*.

94. Finally, Stauffer testified, without elaboration, that Moore's testimony is unclear on other issues and that NWE cannot establish NEI's position. *NWE-3, p. 2*.

<u>CELP Direct Testimony: Richard Lauckhart</u>

95. On January 24, 2006, CELP filed the direct testimony Mr. Richard Lauckhart. Lauckhart addressed certain avoided costs for the 2005-06 contract year,[42] specifically, the failure of NWE to use the "incremental costs of capital including tax effect" and "other escalators" involving indexes and coal costs.[43] He also comments on ratepayer impacts.

96. Lauckhart asserts that NWE has failed to use the incremental cost of capital (ICC) when computing avoided costs as required in prior PSC orders (the PSC Order No.

[42] Lauckhart asserts the bases for CELP's rates are PSC Dockets No. 81.2.15 and 83.1.2. *DR PSC-109*. Apparently, CELP's contract with NWE only references PSC Docket No. 83.1.2, Orders No. 5017 and 5017a; any suggested tie to PSC Docket No. 81.2.15, Order 4865, is through references in orders from PSC Docket No. 83.1.2. DR PSC -111(c). His testimony does not address NWE's September 28, 2005 amendment proposals. On January 27, 2006, CELP filed an errata correcting the page labeled "Attachment 3," changing the title to "NWE embedded cost of debt adopted in Order 6271c." CELP explains which rate it selected out of PSC Docket No. 83.1.2 and how that rate was modified in the contract first amendment. *DR PSC-133(a)*.

[43] CELP explains how its contract with NWE ("first amendment") addresses the issues raised in Lauckhart's testimony -- the first amendment establishes how the rates are computed. *DR PSC -111(b)*. CELP also explains why its contract makes rate issues the PSC's jurisdiction -- CELP and MPC agreed to abide by the PSC's determination based on PSC Docket No. 83.1.2 orders. *DR PSC -135(d)*.

4865 and 5017 sequences).[44] He urges the PSC to address this failure. He explains that the theoretical difference between the ICC and the embedded cost of capital (ECC) is the cost of debt, but adds the equity component can also differ in the ICC compared to the ECC. Whereas the ECC for debt reflects payments that a utility must make to bondholders, the ICC for debt is what would have to be paid if new debt was sold in current markets. *CELP-1, pp. 3-4*. Whereas there should be no difference in the ICC and the ECC for equity, in practice the two may diverge, especially if significant time has passed or if major financial events occurred. Lauckhart expects the ICC to exceed the ECC primarily because of the financial decisions by firms to minimize debt costs and secondarily because NWE is a risky entity now compared to when the PSC last authorized its cost of capital in 2001. The cost of equity will rise with the increased risk.

97. Lauckhart asserts that NWE used the adopted capital structure, and costs of various types of capital, contained in PSC Docket No. D2000.8.113, Order No. 6271c (May 9, 2001). He adds that in “the Filing’s workpapers,” NWE labeled these capital costs as “marginal” costs, a term he equates with “incremental” costs. He maintains NWE most definitely used an ECC, which is neither a marginal nor an ICC concept, and used inputs that do not reflect the contract year capital market. He reasons that NWE used an ECC because that was what the PSC adopted in PSC Order No. 6271c.[45] That cost of equity is not incremental now, although it may have been in 2001. The PSC’s findings in PSC Order No. 6271c are not a current assessment of NWE’s financial

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[44] Lauckhart cited PSC Order No. 4865, ¶ 34: “Capital Costs are to be annualized by applying the companies’ overall incremental costs of capital including tax effect – not embedded cost of capital – and shall be updated annually to reflect the contract year capital market.” He admits not knowing how long the alleged error has existed. Although it appears pervasive in these three consolidated dockets this is the first time that CELP has alleged such an error. He explains the error does not affect the computation of partially escalating rates. *DR PSC-109*. CELP also explains the “partially levelized energy rate” is defined by the first amendment -- after year 16, there is an “escalating energy portion of the partially levelized rate.” *DR PSC -135(c)*. CELP provides the rates that it was paid in the first 15 years in DR PSC-137(a).

[45] Citing MPC witness Ms. Senechal’s testimony supporting a 6.46% embedded debt cost.

condition. In PSC Order No. 6271c, ¶ 83, the PSC found that MPC was not a much higher risk company that needed a much higher rate of return (the PSC authorized a 10.75% cost of common capital). He criticized NWE for not using a cost of equity that reflects "the contract year capital market" *(see PSC Order No. 4865, ¶ 34)*.

98. Lauckhart recommends a 10.65% cost of capital (made up of 13.15% equity costs and 8.15% debt costs, each weighted 50/50.)[46] He proposed that NWE use unweighted incremental costs of equity and debt as that is what SCE (an apparent reference to Southern California Edison) must pay to finance new projects. *CELP-1, p. 7*. He favors the 50/50 equity/debt capital structure because there should be no preferred stock or QUIPS in NWE's capital structure and because NWE's capital structure should be changed to reflect current values (per NWE's 10-Q filed September 2005 with the SEC). In support, he holds that NWE has suggested that its ICC for debt exceeds its ECC for debt. He proposed a higher ICC of debt of 8.15% because SCE currently has better access to capital markets than NWE does (at 7.75% in September 2005). He adds that if NWE's debt cost experienced the same increase from September 2005 to January 2006, as did the yield on 10-Year Treasury Notes that rose from 4.19% to 4.38%, that NWE's debt cost would now be 8.10%. He estimates that the changes he proposed would increase NWE's avoided capacity cost from $65.765/kw/yr to $79.425/kw/yr. The cost of energy would increase from $.042415/kwh to $.050038/kwh.

99. Lauckhart further testified that NWE needs to include the "tax effect" in the cost of capital. *CELP-1, p. 9-10*. This would be achieved by grossing up the ICC for equity to reflect the added revenues that NWE needs to pay taxes on its return on equity. After accounting for these impacts, the ICC of equity (after-tax) of 13.15% rises to 21.37% and the total ICC increases from 10.65% to 14.759%. He recommends, however, that NWE implement his proposal in its "next rate filing."[47] *CELP-1, p. 12.*

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[46] In contrast, NWE proposed a 10.75% cost of equity, 8.54% COST of QUIPS (Quarterly Income Preferred Stock), a 6.4% cost of preferred, and 6.46% debt cost.

[47] If there is an error in the cost of capital, Lauckhart did not support historical rate adjustments. *DR PSC -110(a)*. By "next rate filing" he means the next occasion on

With CELP's proposal (corrected) the cost of capacity would rise from $79.425 to $107.662/kw/yr and the cost of energy would rise from $.050038 to $.065599/kwh. Overall, Lauckhart's corrections would increase the capacity and energy avoided cost payments by roughly 62% and 31% respectively.

100. Lauckhart next identifies three measures of changed avoided cost data that NWE should update annually, which he labels "other escalators." These include: (1) the GNP-IPD, that NWE used to, in part, annualize capital costs; (2) the Unit Labor Cost (ULC) that NWE used to escalate both capital (construction) cost and Operations and Maintenance costs; and (3) the non-residential fixed investment that NWE used to escalate both capital (construction) cost and Operations and Maintenance costs. *CELP-1, p. 13*. He asserts NWE should annually update its Colstrip Units 3 and 4 (C 3 & 4) coal costs that are used to escalate fuel costs.

101. According to Lauckhart, NWE's 2005 filing included both proper and improper computations of avoided costs. *CELP-1, pp. 13-16*. He believes NWE used reasonably fresh estimates of federally-published escalators (previous paragraph, items 1-3), a practice that NWE should continue.[48] He also believes NWE correctly computed the annual cost escalators implicit in the GNP-IPD and Non-Residential Fixed Investment. As for errors, he notes that NWE overstated the annual ULC escalation, however minor the consequences may be. He recommends directing NWE to use the correct annual value of the escalator.

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which NWE updates its avoided cost calculations, which will be pursuant to a final order in this docket. *DR PSC -110(c)*. His references to "updates" and to "this docket" are unclear. CELP provides contract terms that limits rate adjustments in DR PSC-110 (b) and (c). CELP explains that other than interim orders, no prior approved rates can be adjusted. CELP asserts there are only two interim orders (one each in PSC Dockets No. D2004.6.96 and D2005.6.103). *DR PSC-133(c)*. CELP asserts NWE's proposed interim adjustments improperly interpret the definition of incremental capital costs in PSC Order No. 4865 and are inconsistent with the first amendment. *DR PSC-133(e)*.

[48] Lauckhart asserts this is consistent with PSC Order No. 4865, ¶ 33, requiring costs in constant contract year dollars, updated each June 1. *CELP-1. pp. 13-14*.

102. As for NWE's coal cost data, Lauckhart testified that it appears NWE did not include severance taxes. *CELP-1, p. 15-17.*[49] He recommends directing NWE to document whether it included such taxes in its proposed avoided costs. He does not concede that NWE's methodology is otherwise error free and suggests that CELP may revisit how capital costs and O&M were computed for baseload and CT plants. *CELP-1, p. 16.*

103. As for retail rate impacts, Lauckhart testifies *(at CELP-1, pp. 16-18)* that PSC Orders No. 6353c (PSC Docket No. D2001.1.5) and 5986w (PSC Docket No. D97.7.90) approving of the sale of MPC to NorthWestern Corporation protect NWE's retail ratepayers from the impact of higher QF avoided costs.[50] These orders approved a stipulation that caps payments which NWE must pay for the power QFs provide. He adds that the price for contract year 2005-2006 is $32.75/MWh (citing Appendix D), well below the escalating avoided costs that NWE proposed in its June 23, 2005, filing of $42.415/MWh plus $65.765/kw/yr.[51] He concludes that the higher avoided costs which he proposed will have no retail rate impact as "the price limits of Appendix D will continue to protect customers from paying the higher rates that might otherwise result." *CELP-1, p. 17.* He does not believe that NWE's ratepayers are at risk of paying higher "transition costs" due to higher QF avoided costs given the "Final Order" (¶ 21 and 26)

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[49] Lauckhart does not know how long coal severance taxes have existed or whether NWE included them in avoided cost calculations. *DR PSC-111(a).* As for how the first amendment addresses coal taxes, while not a legal expert, he understands such taxes are part of coal costs. *DR PSC-111(e).*

[50] Lauckhart did not know how an increase in payments (of $.011/kwh) for CELP's entire generation would impact NWE's capital structure. He agrees NWE's cost of capital would be determined by the PSC "in a litigated proceeding based upon multiple factors." *DR PSC -112(e).*

[51] NWE explains that $32.75/MWh is the part of CELP's total contract cost that is in the default supply cost. It has nothing to do with the rate that CELP presently receives. The $68.6/MWh is the result of dividing CELP's total payments by the quantity of power delivered for the present contract year (October through March). CELP's actual rate based on nine months of production and payment for the July 2005 through April 2006 period is $70.7/MWh. *DR PSC -144(b).*

fixed the total amount of “transition costs” that relate to QF power. Thus, increased avoided cost payments cannot cause increased transition costs. He asserts NWE’s recovery of costs for QF power is not limited to the prices in the "Final Order" Appendix D. The stipulation approved in the Final Order allowed NWE to collect annually fixed amounts of QF transition costs, at a rate of $25.6 million per year through contract year 2028/2029, and regardless of how much power QFs deliver. This provides shareholders some protections against cost under-recovery, but also protects NWE ratepayers from any future increase in QF avoided costs. *CELP-1, p. 18*.

White Hall Wind Prefiled Direct Testimony: Robert Frantz

104. Robert Frantz filed direct testimony on January 24, 2006. He addressed several proposals by NWE witness Stauffer regarding rates for new QFs.[52] First, Frantz agrees with Stauffer’s proposal to use the QF-1 rate schedule instead of the STPP rate schedule for all new QFs, including those larger than 3 MW.[53] He opposes limiting availability of the QF-1 rate for QFs larger than 3 MWs to five years or until NWE conducts a subsequent request for proposals, whichever occurs first. He asserts that five years would not enable a QF to obtain financing and would violate Montana’s PURPA-related statute, which requires the PSC to encourage long-term contracts between QFs and utilities in order to enhance the economic feasibility of QF projects. According to

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[52] Frantz asserts that the primary thrust of his comments is that the PSC must move forward to adopt rules and procedures that are fair to QFs. *DR PSC-114(d)*.

[53] Frantz is unsure of what NWE’s position is on prospective QF rates given the lapse in time between NWE’s last-filed testimony. He asserts the STPP rate inappropriately reflects an outdated variable cost of generation from a coal resource adding that the variable cost of coal is no longer NWE’s avoided cost. As for the STPP, Frantz may agree that the basis of the tariffed rate was based upon avoided and/or opportunity costs combined with a partial capacity payment, however if limited to “short-term” contracts it will likely prohibit QF development. *DR PSC-114*. He asserts the forward price for 2008 is about $60/MWh. *DR PSC-119*. The forward price for the next five years for baseload energy exceeds $50.00/MWh and such prices should be considered in avoided cost calculations. *DR PSC-115*.

Frantz, standard QF financing requires a twenty-year contract; five years is too short to convince lenders they will receive a return on their investment.

105. Second, Frantz objects to Stauffer's proposal to adjust the QF-1 rate based on a particular project's availability. He believes Montana law permits the PSC to account for project availability and firming expenses associated with intermittent resources in setting QF rates, pointing to § 69-8-604, MCA, as the source of that authority. *DR PSC-113*. However, he asserts that an approach which accounts for the intermittent nature of a resource should also account for other resource attributes like fuel risk. As an example, he notes that while wind resources may generate more unpredictably than a coal-fired plant, they are less likely to be affected by rising commodity prices the way a gas fired plant would. Responding to DR PSC-114, Frantz states that the PSC should consider historical fuel price volatility and accompanying rate impacts when setting QF rates if a utility is exposed to fuel risks pursuant to the terms of a power purchase contract.

106. Frantz asserts that accounting for the intermittent nature of some resources in calculating standard tariff rates would cause rampant confusion and would be difficult to administer. He asserts the PSC should focus on establishing a fair avoided cost tariff for prospective QFs. If a QF and NWE are unable to mutually agree to the tariff rate, or another rate, the PSC should determine a rate in a separate proceeding. Any unique characteristics of the QF can be considered in that proceeding.

107. Third, Frantz asserts the PSC's rule requiring QFs larger than 3 MW to obtain long-term contracts through utility resource solicitations probably violates federal and state law. He points to other states where QFs larger than the state's threshold are eligible for long term contracts with an integrated resource planning-based avoided cost rate.[54] In these states, if the utility and a QF cannot agree on an integrated resource planning-based rate, the PSC conducts a contested case to set a specific rate for the QF.

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[54] The states that Frantz identified include Idaho, Wyoming, Utah, Oregon, and Washington.

In contrast, Frantz asserts the Montana PSC has chosen not to arbitrate disputes, as required by law. Thus, if a QF in Montana doesn't like a tariff rate and complains to the PSC, the PSC simply applies the tariff rate. He asserts this approach renders the complaint process in Montana meaningless. Responding to DR PSC-114, Frantz bases his testimony on his understanding of PSC Order No. 6444c, PSC Docket No. D2002.8.100; his main point is that the current system is not rational or equitable for new QFs.[55]

108. Frantz maintains PURPA is relevant today because NWE and the PSC seek to check PPL Montana's market dominance. He asserts developing alternative generation is one way to do that. He believes PURPA can be a powerful tool for creating opportunities for developers because it requires that utilities fully recover QF-related costs. He adds that PURPA encourages renewable resources in order to diversify the nation's generating portfolio and reduce dependence on fossil fuels. These goals are as relevant today as they have ever been, he says, given that natural gas costs $7.00/Dkt and oil costs over $60.00/barrel.

109. Frantz recommends adopting Idaho's QF approach. Frantz asserts Idaho's standard tariff rate is available to fueled and non-fueled QF projects under 10 MW. QFs 10 MW or larger are eligible for rates derived from an integrated resource planning process. Responding to DR PSC-117, Frantz suggests modifying NWE's default supply process to include a more formal review and approval of a base-case price forecast that would be the basis for long-term QF contracts. If the utility and a QF cannot mutually agree to rates or contract terms, Frantz recommends that the PSC conduct a contested case to settle the issues. He defers to NWE to set the tariff rate. However, he notes that

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[55] PSC Order No. 6444c addressed a complaint by WHW pursuant to § 69-8-603, MCA, requesting a rate determination. Order 6444c determined that WHW is a QF larger than 3 MW and is eligible for a long-term contract with NWE pursuant to ARM 38.5.1905. Under the rule, in order to obtain a long-term contract, a QF must be selected by the utility in competitive resource solicitation. Between solicitations, the QF is eligible for a tariffed short-term avoided cost rate or a negotiated short-term rate. Order 6444c noted that the PSC is in the process of reviewing both the current short-term tariff rate and its basis.

the current rate of $32.75/MWh is significantly below the expected market for the next five years, as demonstrated by: 1) forward prices for power traded at the Mid-C; 2) NWPCC price forecasts; and 3) NWE's price forecasts in its 2005 Default Supply Resource Procurement Plan.[56] He concludes that NWE's avoided costs have increased and the tariff schedules should be adjusted accordingly.

NWE Rebuttal Testimony: Mark Stauffer

110. On February 28, 2006, NWE filed rebuttal testimony from Mark Stauffer. Stauffer addressed testimony from CELP witness Lauckhart and WHW witness Frantz. He rebuts allegations by Lauckhart that in calculating its 2005 QF rates NWE failed to: 1) use the incremental cost of capital (ICC); 2) include coal severance taxes; and 3) calculate correctly the Unit Labor Cost (ULC) escalation. He first addresses the last two issues, admitting to err in calculating the ULC and denying an error involving severance taxes.[57]

111. Stauffer asserts Lauckhart's testimony on using the ICC is a new and significant issue. *NWE-4, pp. 1-11.* He admits he neither used an ICC nor accounted for taxes when computing the QFLT rates CELP receives today, but asserts both were used when the rate was "originally calculated."[58] He explains that NWE escalated the portions

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[56] In addition, Frantz stated that NWE files monthly trackers. The forward price for the next five years for baseload energy exceeds $50.00/MWh and such prices should be considered in avoided cost calculations. *DR PSC-115*.

[57] Stauffer estimates the magnitude of the ULC error for the escalating and partially levelized rates. As for rate corrections, he also explains how in PSC Docket No. D2002.7.80 interim rates were corrected, adding that on no occasion has a rate that was finally approved been corrected and the time-value-of-money reflects the WSJ's published prime rate. *DR PSC-121*. As for errors and true ups to interim rates, he notes that NWE's September 28, 2005, submittal sought to correct known errors in the QFLT escalating and partially escalating rates for contract years 2004-2005 and 2005-2006, adding that CELP, Hanover Hydro, and Pine Creek would all be affected. *DR PSC-126(a) and (c)*.

[58] The escalating and partially levelized QFLT rate components and the system lambda (STPP) are all influenced by the cost of coal and hence the coal tax. *DR PSC-121(c)*.

of the QFLT rate that are partially levelized by applying three U.S. Government inflation measures to escalate values for variables in the rate formulas in PSC Order No. 4865.[59] The annual carrying charges for C 3 & 4 and the peaker require a cost of capital measure and NWE has, in turn, used the "Allowed Rate of Return" (ARR) from PSC Order No. 6271(c).[60] In contrast, he testified that Lauckhart's cite to PSC Order No. 4865 (FOF 34) is to a section of the order that explained how to compute the "new" QFLT rate, a rate that is no longer computed.[61] NWE escalates portions of existing rates. He concludes that FOF 34 has "no bearing" on the rate escalation process. He adds that consistent with FOF 34, NWE used the appropriate ICC, along with taxes and other expenses, to compute the levelized fixed charge factor (LFCF) in the original calculation of the rates that are in CELP's 1994 contract. *NWE-4, p. 3*. In contrast, he asserts that the ICC is applicable to the cost NWE would incur today if it constructed a baseload or peaking unit. He believes that the PSC should reject CELP's opportunistic attempt to increase its rate.

112. Stauffer elaborates on why FOF 34 (PSC Order No. 4865) is irrelevant. *NWE-4, p. 4*. Again, he testifies that FOF 34 applied only to new QFLT rates. The LFCF is used every year in the rate escalation process as an input to compute the annual carrying charges for C 3 & 4. The LFCF includes depreciation, state and federal income taxes, return on equity and debt, insurance and property taxes. He asserts that "these figures" (assumably values for the components of the LFCF) have been held constant since 1988. *Id*. He adds that NWE complied with FOF 34 when it originally computed

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59 In response to DR PSC-109(e) Lauckhart explained that the error that he alleged does not have an impact on the partially escalating rates.

60 NWE explains that the ARR is used (per PSC Docket No. 81.2.15) to compute the baseload and the peaker real carrying charge for the annual escalation process. In regard to PSC Docket No. 83.1.2, the ARR was not used in the original calculation of the long-term rate option as the then-current ICC was used. *DR PSC-141 (c) and (d)*.

61 The PSC Docket No. 81.2.15 orders provide formulas to compute the QFLT rates. *DR PSC-122(b)*.

CELP's rates in 1984. *NWE-4, p. 5*. He concludes that FOF 34, which is titled "Long-Term Rates," clearly deals with the "original calculation of the rates and not the annual escalation calculation." *Id.* He explains that the annual carrying charge (ACC) is applied to the levelized cost to compute the annualized cost on a levelized basis. NWE applied the ACC to the escalated annual construction cost variables for both C 3 & 4 and for a peaker. These escalated construction costs and the ACCs are four of the rate variables in the partially escalating rates.

113. Stauffer also concludes that from an "accounting perspective" the use of the ICC to compute the ACC is incorrect. To include it now would clearly comprise "double counting." *NWE-4, p. 6*.[62] He testifies that Lauckhart's apparent confusion stems from the use of "annualized capital costs" and "updated annually" in FOF 34. These rates were computed annually and were available to "new" QFs, until 1984 when the QFLT rates were suspended and NWE ceased to compute "new" rates. *NWE-4, p. 7*. He adds that Lauckhart could not provide a clear reference requiring use of an ICC in the annual escalation of existing rates.[63] Stauffer concedes that NWE has now used the ARR for several years to compute the ACC for both C 3 & 4 and a peaker and that such use of the ARR is, "at this point of the rate escalation," appropriate.[64]

114. Stauffer testifies that if the PSC decides the ICC should be used, all inputs associated with the variable, such as the current tax, insurance rates should be updated. *Id*. While NWE can update the ARR for debt rates, he notes NWE does not have a fresh cost of equity. He asserts Lauckhart's value of 13.15% is speculative. *NWE-4, p. 8*. If the PSC approves a 13.15% ROE in its next rate case, NWE will use that value to

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[62] Lauckhart's proposal would result in a double counting of taxes. Taxes are in the levelized fixed charge factor and the PSC has never required that it again be accounted for in computing the current cost of capital. *DR PSC-122*.

[63] Stauffer asserts that the contract makes no mention of the cost of capital related to the calculation of rates. *DR PSC-122(c)*.

[64] PSC Order No. 6271c makes no reference to avoided costs but is the source for the ARR. *DR PSC-122(d)*.

compute CELP's rates. He explains that an appropriate capital structure is 50/50 with the currently approved 10.75% cost of equity and an incremental cost of debt based on recent and planned financings.[65] Since incremental taxes were included in the "original" LFCF, grossing up the ICC now, as Lauckhart suggests, would amount to double counting. *NWE-4, p. 8*. He adds that if Lauckhart really wants NWE to recalculate the carrying charge rates with a new ICC, then NWE would essentially recalculate the LFCF. The likely result of using a new ICC, including debt placements, will be lower both carrying charges and rates.

115. Stauffer testified that Lauckhart's analysis and estimate of the impact on ratepayers is "materially" incomplete. *NWE-4, p. 9*. First, CELP's rates would decline if the original calculation was updated using today's lower capital rates. In turn, use of the ICC in place of the ARR will result in more unstable rates, increased uncertainty and impacts on NWE's financial exposure. Second, a 13.15% cost of equity is inappropriate. *NWE-4, p. 10*.

116. Stauffer explains that after Order 4865's rates were suspended NWE proposed a method that continued to calculate the rates in a manner similar to the "new" rates. *NWE-4, p. 10*.[66] NWE later proposed a method that retained the basic formulas

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[65] In 2004, NWE secured a 10-year taxable debt issue with a 5.87% coupon. Its upcoming secured 17-year tax exempt financing will have a coupon of about 4.65%. NWE's "unsecured revolver," also incremental debt, has a spreads of 1.125% over LIBOR for all borrowings that occur under the facility through October 2009. Stauffer explained that the ICC associated with 10.75% equity is about 8.143%. *DR PSC-124(e)*. If an ICC is determined, then NWE suggests using debt costs. *See DR PSC -125(a)*.

[66] Stauffer corrects his testimony to state that NWE continues to compute the STPP rate pursuant to PSC Order No. 4865; the reference was to the QFLT rates. *DR PSC-123*. He also attempts to clarify his testimony in response to DR PSC-126(d): *Regarding the NPV calculation in the 1984-5 filing, NWE used the current marginal cost of capital (MCC) and the most recent construction cost estimates for C 3&4 and the Peaker Unit. Current tax information was also used to arrive at a MCC with tax effects included. The following year the MCC and tax rates were updated and revised C 3&4 construction costs were used. This continued through the 1988-9 rates. From 1988-9 through the present, the variables used for the NPV have been held constant at the 1988-9 levels. That is, at the 1.372 and 1.381 (sic) levels for the baseload and peaker units*. Stauffer

and that included escalators for the variables used in those formulas. The PSC approved the proposal which has been used since that time. Annual escalation has been approved numerous times since 1984. He explains that the cost of capital is used in the annual updates of the ARR as at the time that PSC Order No. 4865 rates were suspended NWE and the PSC had to resolve a unique problem.[67] A method was needed that incorporated the intent of PSC Order No. 4865, and that escalated values for rate components. He asserts that NWE and the PSC arrived at the present method of updating over the course of filings and approvals in the years following the suspension of new rates. Thus, the ARR remains consistent with the use of the ICC in the originally calculated carrying charge. *NWE-4, p. 11*.[68] He asserts this is consistent with "normal regulatory accounting treatment for resources that the PSC Order No. 4865 rates were intended to avoid." Otherwise, each individual unit in a utility's portfolio would collect costs based on a different ICC: "*…the effect of these incremental cost of capital are captured in annual carrying charges that is essentially an ICC, as reflected in the NWE proposal and as previously approved by the MTPSC." Id., italics added*.

117. Stauffer testifies that due to the lack of explicit direction the "annual escalation process" is becoming unmanageable. *NWE-4, p. 11*. This vacuum provides an attractive means by which QFs may attempt to inflate rates. The existing CELP rate of

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explains the carrying charge calculation, escalation methods, and the inflation indices used through time. NWE explains that the 1.372 and 1.381 values are ratios that represent how much money ($1,372 and $1,381) an owner of a baseload or a peaker unit must recover for every $1,000 ("TPV") that it invests if it is to recover costs associated with taxes, return, depreciation and insurance. *DR PSC-143*.

[67] Given that there was no need to then compute the rate anew, a means by which to escalate the rate had to be determined. He adds that due to the absence of any explicit direction a method was created that incorporated the intent of PSC Order No. 4865.

[68] The ARR has been used since the 2001 filing. Prior to 2001 the financial department computed an ICC to analyze new incremental generation additions that was used in annual updates. However, NWE no longer is in the resource development business for the purpose of rate-basing resources. Thus, NWE does not have an ICC applicable to generation. *DR PSC-124 (a) and (d)*.

$76/MWh is in "gross excess" of what a coal unit rate in 1984 currently would be which was what the avoided cost rates were intended to represent avoidance of.[69] The NWPCC estimate of the total cost of a new coal unit was $43/MWh in 2005.[70] He adds, "this confusion has been of considerable benefit to CELP." *NWE-4, p. 12*. The confusion is unnecessary if the various rate components are computed in compliance with the intent of PSC Order No. 4865 (FOF 37). *NWE-4, p. 13*.

118. Stauffer next provides an overview of the PSC Order No. 4865 rates. Such rates were based on actual C 3 & 4 costs, including coal and O & M. *NWE-4, p. 12*. Rates were offered in three formats: escalating; partially levelized; and nominally levelized. QFs had a choice between forecast and actual inflation. *NWE-4, p. 13*. Thus, what is discussed "here" is the escalation of rates, not the re-computation of rates. Computation of the escalating piece is not intended to re-compute annually the rates with a new incremental cost of capital. The ICC is essentially locked in, in the form of the LFCF, for the duration of these rates.

119. Stauffer recommends using three indices -- the Unit Labor Cost, the Fixed Investment Non-residential, and the GNP-IPD.[71] *NWE-4, p. 13*. The first two are weighted 20% labor and 80% investment for capital variables, and 40% labor and 60% capital for O & M variables, with all weightings derived from an EPRI study (cited in PSC Order No. 4865, p. 31, f.n. 2) of relative costs of capital and O & M for coal and gas generators. The only other variable is the "all-inclusive" prior year's cost of coal for C 3

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[69] The $76/MWh is based on the present rates of $57.9/MWh plus $111.97/kw/yr at a 70% capacity factor. The tariffed rate would be $68.6/MWh. *DR PSC-127(a)*. NWE also compared the <u>payments</u> that CELP received (pursuant to its revised contract) with those that it would have received pursuant to the PSC's order. *DR PSC-127(b)*. NWE was asked about a letter that MPC's Mr. Robert Labrie sent on June 20, 1988, to MPC's Mr. Thomas Worring and in which avoided costs were estimated in the range of $.04081/kwh (1989) and $.06819/kwh (2010). *DR PSC-142*.

[70] The $43/MWh value is a real levelized value in 2006 dollars and is comparable to CELP's rates. *DR PSC -144(a)*.

[71] Stauffer explained that the recommended approach has been used since 2001 as proposed by NWE. *DR PSC-128*.

& 4 but escalated by one year using the GNP-IPD. This, he asserts, is fair, equitable, and simple and what the PSC should adopt for QFLT rates. *NWE-4, p. 14*. He explained that the GNP-IPD is used to compute the real annual carrying charge to then arrive at a nominal charge which is applied to the escalated capital costs. *Id.*

120. As for Frantz's testimony suggesting NWE's current QF rate is not sufficient to develop new projects, Stauffer notes that NWE will conduct RFPs on an ongoing basis *NWE-4, p. 14*. QFs will have equal opportunities to win contracts through the RFPs so a "long-term" contract outside the RFP process is not necessary. He asserts a five-year contract at rates that NWE presently pays RFP winning bidders is a significant encouragement for QFs. Stauffer disagrees with Frantz that a single rate adjusted for a QF's availability discriminates against wind QFs. He asserts the single rate is structured so that each QF is paid the full value for what it delivers. Ignoring the intermittency of wind generation would discriminate against all other QFs. Further, if NWE paid for all "nameplate capacity" even if not delivered, someone would have to pay for the additional costs. Stauffer disputes Frantz's suggestion that accounting for the intermittent nature of any resource would cause rampant confusion. Stauffer, asserts his rate proposal is simple and still takes into account the intermittent nature of "some" resources. *NWE-4, p. 15.*

121. Stauffer was asked about the merit of using GenTrader® to estimate avoided costs. *See DR PSC-132 and DR PSC-151*. He responded that GenTrader® is a dispatch model that is used to replicate the operation of hypothetical units in a market environment to analyze various potential resource combinations relative to customers' resource needs. At present, NWE has minimal ability to dispatch; the exception is the 50MW Basin Creek facility. He adds that the primary purpose of developing a Resource Procurement Plan (RPP) is to guide the RFP process and in this regard neither GenTrader® nor the RPP provides relevant costs. He further adds that prior to an RFP process NWE does not know what resource options exist, but once the winning bids are selected it will have relevant QF cost information. He asserts the costs of Basin Creek are included in NWE's currently proposed QF rates. Stauffer explained that the $45 value is a 20 year nominally levelized value that excludes transmission costs (BPA's are presently $3.5/MWh). He explained that the $45/MWh value is based on the NWPCC's forecast of the levelized

value of the regional Mid-C market for the next 20 years. NWE asserts that the $45/MWh is used to determine DSM acquisition levels.

122. Stauffer opposes basing QF rates on opportunity costs, as to base firm power rates on the spot market is inconsistent given NWE enters into long-term contracts to avoid the volatility of the spot market environment. Through RFPs NWE procures stable and reasonably priced contracts that indicate the value of QF power. The spot market is not a source of stable-price power and it would be a disservice to ratepayers to enter into contracts that require paying a firm contract at an unstable spot-market based price. *DR PSC-129(a)*. He declined to provide, for calendar year 2005, the weighted annual average price for sales that NWE has made, adding that neither NWE's accounting system nor invoices have the necessary detail to separate day ahead and real time transactions.[72] *DR PSC-129(c)*. He explained that Mid-C purchases require paying BPA $3.50/MWh plus 1.9% for losses; sales at the same point involve the same BPA charges but also involve a $4.66/MWh plus 4% loss charges on the NWE system.

123. Stauffer was also asked about the inclusion of a capacity payment with the STPP rate. He responded that whereas NWE has proposed a capacity payment in its QF-1 rate, based on a NWPCC peaker cost analysis and using incremental capital costs, if required, NWE would propose to use the same capacity payment as the basis for one-half of an STPP capacity payment. *DR PSC-123(a)*.

CELP Proposed Surrebuttal Testimony: Richard Lauckhart

124. On March 10, 2006, CELP filed proposed surrebuttal testimony from Lauckhart. He asserts that Stauffer raised a new issue by asking the PSC to adopt new and different QF calculations. He also asserts Stauffer's testimony essentially concludes that neither PSC orders nor CELP's contract should be followed if the results seem

[72] NWE did not dispute the accuracy of publicly available data accessible at the FERC: http://www.ferc.gov/docs-filing/equ/data.asp. *DR PSC-130*. NWE explains that it did not provide FERC the underlying purchase price information. Rather that information derives from market suppliers. *DR PSC-148(a)*. NWE continues to hold that short-term market purchases and sales are not an appropriate source for long-term avoided cost information. *DR PSC-148(c)*.

unfair. He charges that NWE intentionally changed the method used to compute rates in an attempt to harm CELP. *CELP-2, p. 2*.

125. Lauckhart concludes, based on NWE's request to change the "escalation formula," and a reading of Owen Orndorff's affidavit of March 10, 2006, that NWE's proposal violates both the PSC's orders and the CELP contract. He asserts that the PSC should not use this proceeding to debate alternative avoided cost rate methods. According to Lauckhart, Stauffer claims that an ICC was used when the rate was originally computed and is not meant to be used with annual adjustments. Lauckhart asserts the only method allowed by PSC orders, and the CELP contract, is the overall ICC, including tax effect, not the embedded cost of capital. *CELP-2, p. 3*. He adds that Stauffer is proposing to litigate the method used by claiming that the ICC calculation must result from a PSC hearing and not from an avoided cost docket (a venue argument). Lauckhart asserts that NWE is avoiding the fact that "alternative approaches are not an option." Neither is permitted by the PSC's decision or CELP's contract. *Id.*

126. Lauckhart next explains why the possibility that the ICC determination "might result" from an involved PSC hearing is not an "appropriate basis" on which to modify the method for performing the calculations.[73] *CELP-2, p. 4*. He concludes that the PSC must now order NWE to calculate the ICC in accordance with the PSC's order and the CELP contract. *Id*. As for Stauffer's testimony that the ICC would usually result from a PSC hearing, not an avoided cost filing, his concern is that an "embedded cost of capital" proceedings can be involved and the PSC's avoided cost orders do not require embedded cost of capital calculations. He adds that if NWE wants to change how the annual escalation is to be performed, then NWE would need to negotiate a contract change with CELP. *Id.*

[73] In DR PSC -134(b), CELP explains that Lauckhart's surrebuttal focuses on the requirements for calculating avoided costs in PSC Docket No. 83.1.2 orders, as required by Tables I and II in CELP's first amendment. CELP adds that NWE ignored Order 4865, ¶ 34.

127. Lauckhart asserts that there is "evidence" CELP was supposed to get prices that increase in years prior to and after year 15 of the CELP contract.[74] *CELP-2, p. 5.* He adds that based on the "original contract" it is clear that CELP "would have" received "partially levelized energy rates of $.03751/kwh for the contract's duration. However, CELP accepted $.0222/kwh in the first year in exchange for increased rates over time and for being "relieved of security requirements" required by Appendix D of the CELP contract.[75] *Id.* He adds that CELP's agreement to accept reduced energy payments in contract year 1, in exchange for increased payments over time, is "evidenced" in "Table 1 of the March 1988 first amendment to the 1984 agreement." He further adds that "Amendment 1" clearly states that these rates were to be "increased based on the compliance filing" pursuant to PSC Docket No. 83.1.2 orders that, in turn, required the use of a tax adjusted ICC.[76]

128. According to Lauckhart, CELP did not challenge NWE's failure to use the "after tax" ICC because it was not relevant to the computation of CELP's rates until the 16th contract year (2004/2005). Thus, this surrebuttal testimony is the first chance CELP had to raise the issue. *CELP-2, p. 6.* He asserts that although Stauffer testified that using

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[74] CELP concedes that PSC Docket No. 83.1.2 orders did not guarantee that partially levelized tariff rates will increase each year of the contract; the escalating portions of energy and capacity rates can normally be expected to increase with various indexes and the operating costs of C 3 and 4. *DR PSC-135(e) and DR PSC-136(a).* Starting with contract year 16, the first amendment provides a contractual formula to determine escalation of CELP's energy and capacity rates. The formula does not guarantee annual escalation but provides for inflation.

[75] As for the relevance of the $.0222/kwh rate, the fixed energy rate in the first amendment reflects the de-levelized rates which make up the original partially levelized tariffed rate. *DR PSC -136(b).* NWE explains when and how it received PSC approval of the amended contract between MPC and CELP. *DR PSC-149(d).* Whereas CELP asserts it accepted $.0222/kwh in the first year, the actual rates NWE claims it paid CELP are different. *See DR PSC-150(a).*

[76] Responding to DR PSC-135(a) and (b), CELP identified those parts of PSC Docket No. 83.1.2 orders and its contract that discuss tax adjusted ICC estimates. CELP also explains what it means by "increased based on…" *DR PSC -136(c).*

an ICC method is incorrect, MPC raised "accounting basis" arguments in 1982, ones the PSC apparently rejected in PSC Order No. 4865b, ¶¶ 16-24. *Id., first Q and A.* He disagrees with Stauffer that the ICC findings of fact in PSC Order No. 4865 only regard how "new rates should be calculated" and not apparently the "administration of existing rates."[77] He adds that CELP has a long term-rate with NWE and that nothing in the order says the calculation is not to be used with long-term rates -- "…it requires that the incremental cost of capital including tax effect, be updated every year." Although NWE (then MPC) ceased offering "these rates to new QFs in 1984" he asserts that nothing in PSC orders allows it to stop making these calculations simply because NWE ceased offering these rates to new QFs -- "*As a consequence, it should be clear that each utility must file annually (June of each year) rates reflecting the Commission's orders in Docket No. 81.2.15 so long as one or more qualifying facilities have contracted for the long-term rate option as defined and computed in Order Nos. 4865a, b, and c*." *(Citing to PSC*

[77] CELP explains that MPC and CELP agreed in the first amendment to base annual rate determinations on PSC decisions in PSC Docket No. 83.1.2 (Orders 5017 FOF 15 and 29, 5017a). *DR PSC-137c*. CELP adds that the ICC is a specific component in determining partially levelized rates. CELP asserts that pricing "under the contract" refers to the requirement to recalculate CELP's energy and capacity rates starting with the 16th contract year, as required by the first amendment. *DR PSC-138a*. CELP states that had it defaulted on its contract in the 14th year and ceased operating as a QF, there was no agreement for NWE to make any necessary compensation. *DR PSC-138(b)*. Apparently, after year 15 there are no predetermined fixed rates and CELP has no idea of how MPC de-levelized rates; further, there are no liquidated damages in any year because MPC de-levelized all of CELP's rates in favor of annual calculations after the 16th year. *DR PSC-138 (c), (d), and (e)*. CELP explains that Tables I and II of Attachment 1 to the first amendment contain the only assumptions CELP and MPC agreed would be used to modify annually the contracted rates. NWE holds that the PSC's role is to approve annually QFLT rates; the use of those approved rates to update CELP's rates is a contract issue between NWE and CELP. *DR PSC -149(e)*. CELP later supplemented its response to PSC-138(d). Whereas CELP first asserted it had "no idea" how MPC de-levelized rates, in its supplemental response CELP states to have located a "significant document" that clarifies how MPC de-levelized rates for QFs, including CELP. De-levelization was achieved by withholding parts of the levelized rate in the early years of the contract as security, with MPC repaying the withheld funds to the QF in the later years of the contract.

Order No. 5017a, ¶ 9, emphasis excluded, italics added). He testified that the PSC orders (PSC Orders No. 4865a, 4865b, 4865c, 5017, and 5017a) that build upon PSC Order No. 4865 must also be considered. He adds that the CELP contract incorporated these "1980's vintage PSC ordered calculations for purposes of determining pricing under the contract." *CELP-2, page 9, first Q and A.*

<u>NWE Surrebuttal Testimony: Mark Stauffer</u>

129. On May 4, 2006, NWE filed the surrebuttal testimony of its witness Mark Stauffer. Stauffer's testimony reiterates the issues related to CELP to demonstrate that the premise that CELP used is fictitious and to respond to the misrepresentations that CELP made. He holds that CELP's misrepresentations appear to create as much confusion as possible. He also finds an inconsistency in CELP's rationale. On one hand, CELP asserts that prior PSC actions are irrelevant to CELP's rates. On another hand, CELP "scolds" NWE for violating PSC orders. This inconsistency makes it nearly impossible for NWE to understand CELP's rationale. *NWE-5, p.12*.

130. Stauffer identifies three issues: 1) should the annual escalation of rates use the ICC or the PSC-approved ARR; 2) should NWE account for "tax effects" a second time when escalating the capital costs for both Colstrip and a peaker; and 3) what measures of inflation should be used to escalate rate variables. Importantly, he disagrees with Lauckhart's testimony that these issues are "contract issues." Rather, they are rate calculation issues that the PSC must determine.

131. Stauffer explains how Lauckhart, in rationalizing CELP's surrebuttal testimony, misrepresents the facts in order to confuse the issues. First, as for CELP's allegation that NWE raised a new issue, involving new and different rate calculations, he maintains NWE made no new rate calculations. As for CELP's position that NWE seeks to re-litigate prior PSC orders, he asserts that NWE is not unwilling to pay CELP $69 rates. He provides rate and cost information to demonstrate the absurdity of the claims that NWE is trying to economically harm CELP, what he labels as "probably the most

lucrative contract of any generator in the region today."[78] He denies changing the method but admits to making a change in 2001 to use the ARR as NWE was no longer in the generation business and it therefore did not have a generation-specific ICC.

132. Stauffer also clarifies that NWE considers in a different light changes that result from changed data inputs. Whereas changes in the methodology would entail a change to the formulas, a change in inputs is to simply use more reasonable sources of information. *NWE-5, p. 13.* To illustrate, NWE labels a change from an ARR to an ICC an input substitution, not a change in methodology. *NWE-5, p. 14.* In any case, he asserts that the difference in opinion between CELP and NWE stems from different interpretations of FOF 34 in PSC Order No. 4865, PSC Docket No. 81.2.15. He adds that, over time, NWE has updated some variables, held others constant, and substituted various sources for information on escalation indices. He cites to NWE's response to DR PSC-126(d) as pertinent to what has transpired since 1984.[79]

133. Second, Stauffer takes issue with Lauckhart's testimony that asserts *"…this proceeding is designed to simply make the annual calculations required by prior Commission orders and in accordance with* <u>*contract*</u> *requirements." (italics and*

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[78] In March 1, 2006, rebuttal testimony, Stauffer asserts that the existing CELP rate, of $76/MWh, is in "gross excess" of what a coal unit rate in 1984 would currently be, which was what the avoided cost rates were intended to avoid. The NWPCC estimated the cost of a new coal unit was $43/MWh in 2005. *See f.n. 80 for further discussion*. In data request PSC-149(a) NWE was asked to explain what part of CELP's "lucrative" rate stems from having received below cost rates in the early years. NWE responded that CELP is presently receiving, and will receive for the duration of the contract, rates in excess of the original rate they signed up for.

[79] NWE's response to DR PSC-126(d): *Regarding the NPV calculation in the 1984-85 filing, NWE used the current marginal cost of capital (MCC) and the most recent construction cost estimates for Colstrip 3&4 (C34) and the Peaker unit. Current tax information was also used to arrive at a MCC with tax effects included. The following year the MCC and tax rates were updated and revised C34 construction costs were used. This continued through the 1988-9 rates. From 1988-9 through to the present, the variables used for the NPV have been held constant at the 1988-9 levels. That is, at the 1.372 and 1.381 levels for the baseload and peak units respectively. This effectively locked in the MCC rate and the tax rates at the 1988-9 level.*

emphasis added). He disagrees that "contract requirements" have any relevance in this proceeding, as they are rightfully before a court and not the PSC. He asserts CELP's notion that its contract is relevant to rate escalation issues is absurd.

134. Third, Stauffer rebuts that part of Lauckhart's testimony that asserts to have not proposed anything new. He holds that Lauckhart's double counting of tax effects is certainly a change. As for CELP's suggestion that the PSC's choice is between the use of NWE's embedded costs of capital or the tax adjusted ICC that CELP proposed, he disagrees and asserts that the "choice" is between the embedded cost of capital or the ICC. He asserts CELP tried to "co-join" the issues to give its absurd double taxation proposal credibility. *NWE-5, pp. 10-11*. As the ICC issue "may have merit," he separates the two issues and asserts that because the tax adjusted ICC was in the initial calculation of rates, and because NWE continues to escalate the tax adjusted cost of capital each year, this should not be an issue in this case and not even CELP has suggested that taxes should be counted twice. He adds later that, with the "ratio" of rates combined with CELP's double counting of taxes, CELP would receive a windfall profit for the remaining term of its contract, of about $15.8 Million per year for 20 years. *NWE-5, pp. 9-10*. He also adds that the impact of CELP's recommendations will have no direct pass-through impact due to increased costs on ratepayers; however, indirect impacts would be significant as any unrecovered costs would impact NWE's financial health. *NWE-5, p. 17*. Thus, a $16 million disallowance, that rating agencies classify as "imputed debt" and the appearance of an unstable contract, would be viewed negatively.**[80]**

135. Whether NWE should use the embedded or the ICC is a separate issue. NWE agrees that, if directed, it will use the ICC. NWE's ICC is 8.143% which contrasts with the 8.464% ARR used in the annual rate calculation.

136. Fourth, as for "escalators" and Lauckhart's assertion that NWE would need to negotiate with CELP for a change in the contract, Stauffer responds that Lauckhart has

[80] Stauffer testifies that "this project" (CELP) is owned by out of state capital investment institutions (including Michael Dell's Paragon Capital) and general partners.

a fundamental misunderstanding of how QFLT rates are escalated. NWE has proposed "indexes" for PSC approval and NWE is under no obligation to negotiate these matters with CELP. Again, he finds absurd CELP's notion that its contract is relevant to rate escalation issues. As for changes in the escalation rates, he explains how beginning in 1989-90 NWE changed one index, the Handy Whitman Index (HWI), to a weighted average measure of Data Resources Incorporated indexes. *NWE-5, pp. 15-16*. In 1995, NWE proposed changing the construction cost index. And, in 2003 NWE proposed using a capital cost escalator of 20% unit labor and 80% fixed investment and an O & M escalator of 40% labor and 60% fixed investment. He notes that, with the exception of the present consolidated dockets, all changes he described were approved. *NWE-5, p.16.*

137. Fifth, regarding Lauckhart's assertion that the issue of computing "after tax incremental cost of capital" was not relevant until year 16 of CELP's contract (contract year July 1, 2004, to June 30, 2005) and that this is the "first chance" CELP has had to raise the issue, Stauffer notes that since CELP has intervened in each of the consolidated dockets, it has had an "open ended" opportunity to provide input. When CELP (witness Orndorff) filed testimony in the first of these three dockets it raised neither the double counting of taxes nor the use of the average rate of return issues.

138. Stauffer asserts the 2004-2005 contract year rates are not the first rates relevant to computing year 16 rates because year 16 rates are based on CELP's year 15 rates. Year 16 rates are based on CELP's year 15 rates times the ratio of the 2004-2005 rates over the 2003-2004 QFLT rates.[81] In addition, while the 2003-2004 rates are the

[81] For an explanation as to how CELP's rates were computed, NWE also points to Tables I and II of the first amendment to the CELP contract. The first amendment shows how the levelized portions of the partially levelized rates were converted to escalating rates for years 1 through 15. Stauffer explains that the difference between the levelized rate and the escalating rate is what CELP would have paid for security in the front years. He adds that all of the values were derived from the PSC Order No. 5017 (series) methodology. Instead of CELP receiving the full levelized rate and paying security into an escrow account, the security payment was removed from their rate, and they were simply not overpaid. The money they would otherwise have received is now being paid to them, with interest, in that from the 11th year on the CELP rate is greater than the levelized rate. The escalating part of CELP's rate was not affected by the first amendment. *DR*

first rates that directly impact the year 16 rate calculation for CELP, in reality all the QFLT rate filings are relevant to CELP's present rates. He appears to suggest that the ratio approach used to compute increases to CELP's rate, which began in year 16, is unique to CELP. *NWE-5, p. 9.* He adds that the numerator and the denominator in the ratio must be calculated using the same method.[82] Since NWE's ratios are lower for energy (0.8589) and capacity (0.8976) than result from CELP's advocacy for energy (1.6079) and capacity (1.4855), he explained that the difference stems from the lower real cost of capital. Inflation of 2.51% exceeded the prior year's rate of 1.05% and therefore lowered the same nominal capital cost of 8.46%. *NWE-5, p. 11*. Because "recent refinancings" are an appropriate measure of NWE's ICC, he asserts that it is appropriate to use the 8.143% ICC for the three years of rates decided in this proceeding. *NWE-5, p. 12*.[83]

COMMISSION DECISION

139. The PSC bifurcates the issues to be decided into two areas, CELP and non-CELP contract related QF rate issues.

<u>CELP ISSUES</u>

140. In the following discussion the PSC organizes and consolidates the CELP issues for decision making into the following three issue categories: (1) rates and costs; (2) contract; and (3) other (non-rate, non-costs, and non-contract).

PSC-144(c). CELP's rates did not deviate from the PSC methodology. *DR PSC-144(d)*. NWE asserts, however, that the ratio approach used to compute CELP's rates is not found in any PSC order. *DR PSC-145*.

[82] The equation is illustrated in NWE-5, p. 9:
CELP year 16 Rates = [CELP year 15 rates] [(QFLT 2004-05 rates)/(QFLT 2003-04 rates)]

[83] Regarding refinancings, Stauffer explains that NWE's ICC of 8.143% was based on one debt refinancing and the PSC Order No. 6698a debt ceiling of 5.2%. *DR PSC -147(d)*.

Rate and Cost Issues

141. There are several interrelated rate and cost issues that involve the cost of capital and tax effects. Two other issues are resolved that include escalation indices and coal costs. The PSC address, in turn, each of these items.

Incremental Cost of Capital (ICC)

142. The PSC has in prior dockets required the use of the incremental cost of capital (ICC) to compute QF avoided cost rates. Notwithstanding this prior requirement, NWE witness Stauffer admits that NWE has not recently used an ICC estimate. Instead, NWE used the allowed rate of return (ARR) from PSC Order No. 6271(c) to compute annual carrying charges (ACCs) for both C 3 & 4 and for a peaking plant.[84] Up until the time of its annual 2001 QF filing an ICC or a marginal cost of capital (MCC) was used. NWE (then MPC) then substituted, without notice in its annual filing, an ARR for the ICC. While requiring the use of an ICC estimate for purposes of these three consolidated QF dockets, the PSC will, in the future, give consideration to the relevance of substituting an ARR for an ICC (or an MCC), once a sound record exists and not before. Therefore, in these consolidated dockets NWE must again use an ICC to compute the ACC.

143. As for which ICC NWE must use, the PSC was presented with two proposals, one from each from CELP and NWE. CELP's proposal features an ICC estimate of 10.65%. NWE proposed an ICC of 8.143%. As a general matter, the PSC

[84] In its July 30, 2001, filing by Pat Corcoran, MPC stated to make only two changes to the "methodology" used in prior filings. The change in methods involved baseload variable O & M and coal costs. In its October 18, 2001, revised filing, MPC asserts that its prior filing had draft work papers that were not the basis for the rates it filed. MPC retracted its prior assertion to have made a change in "methodology." MPC makes no mention of the cost of capital in the cover letter of either filing. Each filing contained a proposed 8.464% "marginal cost of capital" (MCC). The October 18, 2001, filing actually used MCC and ICC interchangeably to describe the same value. As recently as in its June 30, 2003, annual QF avoided cost filing, NWE still referred to the 8.464% as the MCC. In its last docket in this consolidated proceeding NWE again filed on June 23, 2005, labeling the 8.464% a MCC. In his May 4, 2006, Surrebuttal, NWE's Stauffer labels the 8.464% value an ARR (*see NWE's response DR PSC -141(c) and (d), wherein NWE ties the value to PSC Order No. 6271(c) involving revenue requirements*).

finds that while the ICC estimate is a valid issue in avoided cost dockets, a debate emerged too late in the procedural process to provide for a robust record.[85] Therefore, the PSC finds that it would be unwise to adopt either the CELP or the NWE estimate. In future QFLT compliance filing dockets, beginning with the NWE 2006/2007 filing, the PSC will again consider the basis for the cost of capital that is used. The cost of capital issue (ICC, MCC, or ARR) may, with proper notice, also be addressed in a traditional rate case. As explained below, the PSC rejects the NWE and the CELP ICC estimates and proposals and requires NWE to use a recently approved ICC estimate.

144. The PSC finds that NWE must use the MCC that MPC filed for QFLT rate making in PSC Docket No. N2001.1.2. On December 28, 2000, MPC made its annual QF filing. That filing also included a 9.44% MCC. At a regularly scheduled April 3, 2001, work session the PSC approved of MPC's filing. This 9.44% MCC must now be used to make final the rates in these consolidated QF dockets. On a going forward basis, the PSC expects nothing less than the utmost transparency in NWE's filings.

145. CELP and NWE did not agree on when to implement any cost of capital adjustment. In his January 24, 2006, rebuttal testimony, CELP's witness Lauckhart testified that his avoided cost concerns were limited to the 2005-2006 contract year. In contrast, he also recommended implementing his proposals in NWE's "next rate filing." NWE's witness Stauffer testified that if a change is made, that all three years of the interim approved rates should be revised.

146. The PSC finds that NWE must use the above approved ICC of 9.44% to recompute the QFLT avoided costs for each of the three years of filings in this consolidated proceeding.

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[85] CELP's witness Lauckhart stated that NWE's cost of capital would be determined by the PSC "…in a litigated proceeding based upon multiple factors." *DR PSC-112(e)*.

Tax Adjusted ICC

147. The PSC was for the first time apprised of CELP's concern about including taxes in the ICC when CELP's witness Lauckhart filed his January 24, 2006, rebuttal testimony. The PSC finds such an adjustment inappropriate as NWE includes tax effects in the ACC *(see also TR, pp. 307-308).* Based on MPC's December 21, 1983, compliance filing in PSC Docket No. 83.1.2 (p. 39 of 43), it is evident that tax effects were addressed in developing the net present value of revenue requirements. The ACC calculation (p. 37 of 43) did not include an ICC tax adjustment. In its June 18, 1984, compliance filing, also in PSC Docket No. 83.1.2, the same method was used again. The method established in 1983 has continued to be used. The PSC therefore does not find that NWE must now begin to adjust the ACC a second time for taxes. Also, the PSC would note that the parties to PSC Docket No. 83.1.2 did not in their review of the above compliance filings raise concerns such as those that CELP has now raised. In addition, any QF that signed a contract with MPC to receive rates based on the QF pricing policies established in PSC Docket No. 83.1.2 would have had access to that docket's record, including the above compliance filings. In turn, the method that the PSC approved for use would have been evident.

ICC Computational Frequency

148. In its initial 1983 and 1984 compliance filings, MPC made ICC estimates for QFLT rate calculations and included the same in its QFLT rate calculations. MPC appears to have made ICC (or MCC) estimates since 1983. Although MPC and NWE label the 8.464% value a MCC value, having done so as recently as in its June 21, 2006, QFLT avoided cost compliance filing, the PSC now understands that the value is not a MCC value. Instead, it is a value based on NWE's ARR. This change by MPC fails any reasonable minimum standard of transparency. For purposes of QFLT compliance filings that NWE must make to update its rates, an annual calculation is required. NWE and intervenors will have the opportunity each year to debate the proper value for an ICC, including whether an ICC ought to derive from a similar rate case process as the 8.464% value derived.

Levelized Fixed Charge Factor (LFCF)

149. NWE asserts to have frozen the LFCF since 1988. Embedded in the LFCF are the effects of taxes, depreciation, and so forth. Moreover, the LFCF is designed for specific types of plant (*e.g.*, C 3 & 4, peaking). NWE testified in favor of refreshing all inputs in the LFCF if an ICC is used.

150. The PSC made abundantly clear in its PSC Docket No. 83.1.2 orders (PSC Orders No. 5017 and 5017a) that a significant problem in encouraging QF development had been rate uncertainty. *PSC Order No. 5017, FOF 10*. That was a major reason why the PSC changed the method used to compute QF avoided costs that was established in PSC Docket No. 81.2.15. The PSC addressed the problem of rate uncertainty in PSC Docket No. 83.1.2, in part, by requiring three rate options to be tariffed. In its PSC Docket No. 83.1.2 orders, the PSC required that the "Base Long-Term Rate" would be the rate basis for the fully escalating QFLT rate option *(PSC Order No. 5017, FOF 54)* which is one of the rates that the amended CELP contract cites. The PSC clarified that with the QFLT escalating rate option, plant costs (for C 3 & 4 and a peaking plant), the coal and the variable O & M costs, would escalate. *PSC Order No. 5017a, FOF 17, 18*. The PSC further clarified that the Base Long Term Rate shall continue to be computed with revised cost estimates until the PSC replaces the existing proxies for base load facilities with other base load facilities. That is, as evident from the PSC's findings (in above referenced PSC Docket No. 83.1.2 orders) the PSC may choose to replace C 3 & 4 at a later date.[86] In turn, it would follow that the inputs into the LFCF may change if a new proxy for base load plant costs were used in the escalating rate option. The replacement would affect the escalating long-term rate option *(PSC Order No. 5017a, FOF 23, 24)*. Therefore, there is at least one circumstance when the LFCF could be changed consistent with the PSC Docket No. 83.1.2 orders.

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[86] NWE held that only inflation adjustments are made to the escalating rates. *TR 239-240*.

151. Therefore, Stauffer's recommendation to revise the LFCF if an ICC is used is not consistent with MPC's use of differing ICCs (or MCCs) after 1988 and until 2001, when MPC first substituted an ARR for the cost of capital. While the LFCF could be changed consistent with the PSC Docket No. 83.1.2 orders, no change to the LFCF will be made in this consolidated QF proceeding.

Escalation

152. CELP's witness Lauckhart testified in favor of annual updates to three measures of changed avoided costs -- the GNP-IPD, the Unit Labor Cost (ULC), and the non-residential fixed investment used to escalate capital (construction and O & M costs). He testified that the ULC escalator needs to be corrected. NWE makes an annual update to its indices. The PSC finds that any dispute that CELP had with NWE's choice of inflation indices appears to be resolved for purposes of computing rates in these consolidated QF dockets.[87]

153. The PSC will not approve of NWE's proposal asking that the PSC approve of NWE's escalation methods and assumptions for all future QFLT filings *(see NWE Reply Brief to CELP's response Brief, September 13, 2006, p. 13)*. NWE may recycle the method approved here with new information (assumptions) and make annual filings accordingly. What is a "method" versus what is an "input assumption" may be addressed on those occasions when a party recommends a change. The PSC will in the future entertain proposals that involve changes in escalation. Finally, NWE's mistaken use of three quarters of data must be corrected to use four quarters of data.

Coal Severance Tax

154. CELP's witness Lauckhart testified that coal costs should include severance taxes. NWE testified that severance taxes are included.

[87] Lauckhart testified that NWE correctly computed the annual cost escalators implicit in the GNP-IPD and Non-Residential Fixed Investment.

155. The PSC understands that this issue, of whether NWE included such taxes, is also resolved *(see TR, p. 226, NWE's proprietary data responses, and DR CELP-005 and CELP-009)*.

Compliance Filing

156. Within three weeks of the date of the Final Order in this docket NWE must submit rates that are in compliance with this order. Work papers must show the rate calculations. NWE must also submit work papers that show all adjustments, involving the time-value-of-money, to the interim approved rates in these consolidated QF proceedings. The work papers must be submitted for each individual QF affected by the above findings.

2. Contract Issues

157. A number of contract issues were raised in the course of these consolidated proceedings. As a general matter, the PSC will not engage contract issues. The PSC identifies the following contract issues.

Making CELP Whole: Prior Year's Underpayments

158. CELP's witness Orndorff disagreed with the PSC for having raised contract issues. His disagreement stems from the PSC's prior conclusion that it has no jurisdiction over such (contract) matters.[88] He did testify that the first amendment between CELP and MPC freed CELP of any security obligation and it freed NWE of any refund obligation. NWE would have a $57 million obligation if it terminated the

[88] In an October 17, 1997, Final Order (PSC Docket No. D97.7.127, et al.,) the PSC declined jurisdiction over matters regarding the curtailment of power purchased from QFs. The PSC concluded that it generally does not have jurisdiction to decide disputes between utilities and QFs over the terms and conditions of executed contracts.

agreement (a concern apparently related to NWE's bankruptcy). Orndorff, however, also testified that CELP must now be made whole for the prior years' underpayments.**[89]**

159. Insofar as CELP's testimony that it must be made whole for prior year's underpayments pertains to the $57 million estimate, the PSC finds that the issue is a contract matter and one that the PSC will not further address. Insofar as CELP's testimony pertains to cost and rate issues, the PSC has already addressed issues involving the cost of capital and related matters (*e.g.*, adjustments for tax effects). Again, there remains no issue requiring a PSC finding.

Promptly Assume the Contract

160. In apparent relation to the then-ongoing NWE bankruptcy proceeding, CELP's Orndorff recommends that QF contracts be "promptly assumed" as there is no viable alternative to acquire cheaper resources without affecting the reorganization.**[90]** He adds, that because a delay will only result in a weaker successor company and higher ratepayer costs, NWE's filed plan should be reviewed and implemented as soon as practicable if NWE is to remain a "separate entity." By "promptly assumed," CELP means that the "Plan of Reorganization" must necessarily deal with the treatment of executory contracts. "Assumption simply means executory contracts in existence prior to the bankruptcy proceeding should continue after the reorganization of NWE as if the bankruptcy did not occur." *See DR PSC-027*.

161. The PSC finds that this matter is a contract issue and one that the PSC need not address.

[89] CELP adds that "…any action to void the amendment will result in significant additional payments to CELP to recover previous underpayments…" CELP further added: "Assuming AEM/CELP does perform for the contract term, MPC/NWE has an obligation to refund the AEM/CELP security funds in the later years."

[90] By "promptly assumed," CELP means that the "Plan of Reorganization" must necessarily deal with the treatment of executory contracts and "Assumption simply means executory contracts in existence prior to the bankruptcy proceeding should continue after the reorganization of NWE as if the bankruptcy did not occur." *DR PSC-027*.

ICC and Tax Adjustments

162. Earlier in this order the PSC explained why it disapproved of CELP's proposal asking that the cost of capital must be adjusted for tax effects. The PSC's findings addressed only the cost and rate aspects of the issue. If there are other aspects of the issue that violate the contract then, by definition, the issue is a contract matter, one that the PSC will not address.

Escalation Adjustment for Shorted Rates

163. CELP asserts that a project commencing operation in 1989 should have received the associated year's rates. Because MPC ignored six years of escalation (1984-1989), CELP holds that it was "shorted" for the predetermined rates during the first 15 contract years; whereas CELP is entitled (per the contract's first amendment) to whatever the annual rates are in 2004/2005 and 2005/2006, regardless of whether MPC selected the first year 1984 tariffed rates instead of first year 1989 rates for payments to CELP for years 1-15, the escalating energy and capacity rates beginning in year 16 must take into consideration for the six years during which MPC shorted CELP. CELP calls this an "escalation adjustment" that "catches up" for MPC's understatements of CELP's rates. *CELP's August 15, 2006, Reply Brief, pp. 3, 9, and 10*. CELP re-states that NWE must recognize that under PSC Docket No. 83.1.2 an escalation adjustment for five years which "catches up" for MPC's understatement of CELP's rates in 1989 based on 1984 rates and that corrects errors made by NWE and MPC in the first 15 years starting in 1993. *See CELP's August 31, 2006, Response to NWE's Post-Hearing Brief, pp. 6-7.*

164. CELP explains that NWE would like the PSC to ignore that CELP's first year contract rate was $.02222/kwh instead of the tariffed compliance filing rate of $.03751/kwh. In contrast, CELP asserts that NWE's Late-Filed Exhibit # 2 shows the appropriate energy rate to be $.02891 in 1990. CELP calculates the "underpayment cost to CELP of $57,000,000." *See CELP's August 31, 2006, Response to NWE's Post-Hearing Brief, pp. 7-9.*

165. NWE characterizes CELP's comparison as suggesting that because CELP's delivery did not begin until 1989 that CELP is pursuing a "catch up" in their contract.

NWE emphasized that the contract year is not identified by the "base year" (Column 2, Late-Filed Exhibit # 2). *NWE's September 13, 2006, Reply Brief to CELP's Response Brief, pp. 5-6.*

166. This issue appears to have emerged for the first time in CELP's brief. The issue is a contract matter that the PSC will not address.

CELP/MPC Contract: Use of the ARR

167. In his March 10, 2006, surrebuttal testimony, CELP's witness Lauckhart testified that CELP has held that NWE's substitution of an ARR for the ICC is a violation of the PSC orders and a violation of the CELP contract. According to CELP, a contractual change must be negotiated with CELP.

168. Whether the PSC may find that an ARR can and should substitute for an ICC is both a costing and pricing issue and a contract matter. A party may testify in any future proceeding, including in the recent PSC Docket No. D2006.6.94 proceeding, on the relevance of using an ARR and whether it is consistent with PSC orders.

CELP/MPC Contract's First Amendment: The Ratio Approach

169. With the first amendment to the CELP/MPC contract rates are computed beginning in year 16 of the 35 year contract, using a formula, the so-called ratio approach.[91] Although the ratio approach uses PSC determined values for rates (energy and capacity), the ratio approach is not found in any PSC order. NWE asserts that because CELP's expert wants to use the "new calculated number" in only one year (the numerator) that the proposal is not consistent with using his corrected numbers in all years (the numerator and the denominator). *See NWE's August 18, 2006, Post-Hearing Brief, p. 4.*[92]

[91] In his May 4, 2006, surrebuttal, Stauffer identifies among several issues the relevancy of the prior year's rates in the calculation of year 16 rates when the ratio approach is first integrated into CELP's rate calculation (2004/2005 contract year).

[92] For energy the equation in the first amendment defines:

170. The ratio approach is purely the result of negotiation. How the ratio approach is implemented is purely a contractual matter. As the PSC has no record of any QF having selected the PSC Docket No. 83.1.2 escalating rate option, after the docket's rates were no longer offered and up until the time that CELP and MPC negotiated the 1st amendment, there would appear no need for MPC to have computed the escalating rate option.

3. Other Issues

171. There emerged in testimony or in briefs issues that are neither rate/cost nor contract related issues.

Out-of-Market Cost Estimates: 1998-2004

172. Based on a disagreement with MPC's out-of-market cost estimate, CELP's witness Orndorff argued that the actual market prices that were used should be updated (1998-2004) to see if the QF contracts remain out of market.[93]

173. The PSC declines to order NWE to make such estimates. The amount by which the market value of QF power was understated and, as a result, the out-of-market stranded cost estimate was exaggerated is not clearly relevant to the issues in these consolidated dockets.[94]

$ER_n = [ER_{n-1}]\ \mathbf{x}\ [(ESC\ ER_n - PESC\ ER_n) / (ESC\ ER_{n-1} - PESC\ ER_{n-1})]$ where,

ER_n, $ESC\ ER_n$, $PESC\ ER_n$ are respectively the energy rate, the escalating energy rate and the escalating portion of the partially levelized energy rate (all for contract year "n").

[93] See NWE's response to DR PSC-017(a) for an explanation of the out-of-market estimate.

[94] Re: final order PSC Order No. 5986w in PSC Docket No. D97.7.90 on MPC's electric utility restructuring transition plan (also PSC Order No. 6353c in PSC Docket No. D2001.1.5).

Ratepayer Impacts

174. As for retail rate impacts, CELP's witness Lauckhart testified (pp. 16-18) that, by virtue of the PSC's January 31, 2002 order (PSC Order No. 6353c, PSC Docket No. D2001.1.5; but also see PSC Order No. 5986w in PSC Docket No. D97.9.90) approving of the sale of MPC to NorthWestern Corporation, NWE's retail ratepayers are protected from higher QF avoided costs.[95] Ratepayers are protected as the order approved a stipulation that caps payments which NWE must pay for power that QFs provide. He adds that the price for contract year 2005-2006 is $32.75/MWh (citing Appendix D of the order), well below the escalating avoided costs that NWE proposed in its June 23, 2005, filing of $42.415/MWh plus $65.765/kw/yr.[96] Lauckhart concludes that the higher avoided costs that he proposed will have no retail rate impact as "the price limits of Appendix D will continue to protect customers from paying the higher rates that might otherwise result." (p. 17) Lauckhart does not believe that NWE's ratepayers are at risk of paying higher "transition costs" due to higher QF avoided costs. They are not at risk as the "Final Order" (paragraphs 21 and 26) fixed the total amount of "transition costs" that relate to QF power. Thus, increased avoided cost payments cannot cause increased transition costs. He testified that NWE's recovery of costs for QF power is not limited to the prices in Appendix D (of "Final Order"). The stipulation approved in the Final Order allowed NWE to collect annually fixed amounts of QF transition costs, at a rate of $25.6 million per year through contract year 2028/2029, and regardless of how much power QFs deliver. This provides shareholders some protection against cost under-

[95] Lauckhart did not know what the impacts on NWE's capital structure would be from an increase in payments (of $.011/kwh) for CELP's entire generation. He agrees that NWE's cost of capital would be determined by the PSC "…in a litigated proceeding based upon multiple factors." *DR PSC -112(e)*.

[96] NWE explained that $32.75/MWh is the part of CELP's total contract cost that is in the default supply cost. It has nothing to do with the rate that CELP presently receives. The $68.6/MWh is the result of dividing CELP's total payments by the quantity of power delivered for the present contract year (October through March). Their actual rate based on nine months of production and payment for this July 2005 through April 2006 period is $70.7/MWh. *DR PSC-144(b)*.

recovery, but also guards NWE's ratepayers from any future increase in QF avoided costs (p. 18).

175. CELP holds that, given the contract first amendment mandates an annual update compliant with D83.1.2, both MPC, NWE must have been aware of the "stranded costs" owed to CELP beginning with contract year 15 (that CELP asserts started July 1, 2004).[97] CELP adds that the contract first amendment obviously required contract year 16 to use "…fully escalated values existing in 2004, or, for that matter, the millions of dollars they underpaid CELP in the first 15 contract years…," (see CELP's August 15, 2006, Reply Brief on Interim Rates, p. 9).

176. NWE holds that there can be unintended consequences that will affect the ability of NWE to finance its operations that could impact ratepayer rates (see NWE August 18, 2006 Post-Hearing Brief, p. 5). The Montana Consumer Counsel appears to hold that ratepayers are fully protected (TR 64), a point with which NWE, however, appears to disagree (TR 72).

177. The PSC finds that whether there are unanticipated indirect ratepayer impacts depends upon the PSC's QFLT rate decisions. In any event, it is not a consideration that drives the proper computation of rates that must be computed pursuant to Order 83.1.2.

PSC Order No. 4865, FOF 34

178. The final order in PSC Docket No. 81.2.15, PSC Order No. 4865, was the foundation for ratemaking policies and methods adopted in the PSC's orders in PSC Docket No. 83.1.2. The PSC Order No. 4865 long term rate option was grandfathered when the final orders were issued in PSC Docket No. 83.1.2. While some of the policies and methods adopted in PSC Order No. 4865 were contained in the QF ratemaking

[97] There is an inconsistency in CELP's cross reference of contract years (e.g., 1, 2…16) and the associated time period. In its August 1, 2006, Opening Brief on Interim Rates (p. 6), CELP correlates contract year 16 with 2004-05. Thus, by implication contract year 15 would necessarily be 2003-04. In its August 31, 2006, Response to NWE's Post-Hearing Brief (p. 5) CELP again correlates contract year 16 with 2004-05.

methods and policies adopted in PSC Docket No. 83.1.2, the rates ordered differ from those in PSC Docket No. 81.2.15. It is in the final analysis the PSC Docket No. 83.1.2 QFLT rates that NWE must now compute and annually file with the PSC.

QUALIFYING FACILITY RATE ISSUES

179. In the following findings the PSC addresses short-term and long-term rate issues, wind generation, and the renewable energy credit issue.

Short-Term Power Purchase (STPP) Tariff

180. There are two main issues surrounding the STPP tariff: 1) whether or not to grandfather the tariff offering; and 2) the cost basis for short-term transactions regardless of whether the STPP tariff is grandfathered.[98] Optional cost bases for short-term transactions include short-run (proprietary) operating costs for a coal unit, as proposed by NWE, or, in the alternative, a rate that is based on purchased power costs.

181. The PSC finds that the present cost basis for the STPP rate does not accurately reflect NWE's short-term avoidable cost. The PSC also finds that the STPP appears to serve no present useful purpose. Therefore, the PSC determines that the STTP tariff must be abolished. The PSC adopts a market-based rate option within the long-term, standard QF tariff schedule (see discussion below). That market-based pricing option is a reasonable replacement for the STPP tariff and rate. QFs currently paid the STPP rate will be paid according to Option 2 in the long-term standard QF tariff rate, unless contracts specifically provide otherwise in the event the STPP is terminated, in which case the PSC will reconsider how the STPP rate should be computed.

Long-Term, Standard QF Tariff

182. This PSC decision on the long-term, standard QF tariff involves several interrelated issues, including the basis for rates, the availability of the standard tariff (*i.e.*, size threshold issues), allowed contract lengths, whether tariffed rates should be

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[98] NWE proposed later to "abolish" the STPP-1 rate. *Brief, p. 11.*

differentiated according to various production technologies (*e.g.*, wind, hydro, thermal cogeneration), and whether NWE's total purchase obligation under the long-term tariff should be limited (*i.e.*, capped). All of these issues are addressed below.

183. The PSC finds that NWE's current QF-1 tariff rate should be replaced with two rate options. One option must be tied to NWE's recent PPL contract and the other market-based rate option shall have two sub-options.

184. Option 1. The first long-term rate option must reflect the simple average of the prices in NWE's July 5, 2006, seven-year power purchase agreement with PPL Montana, $49.90/MWh. Contract lengths of up to fifteen years must be available. As a recent contract with power deliveries starting in July, 2007, the PPL Montana contract better reflects actual avoidable costs than NWE's proposal of a weighted average of all NWE's existing, non-QF power purchase agreements. In addition, this rate generally approximates the $45.00/MWh avoided cost NWE used to determine the cost-effectiveness of demand-side resources in its 2005 electric default supply resource procurement plan[99] and NWE's $52.00/MWh estimate of the cost of a new pulverized coal plant, [100] both of which NWE developed using the NWPCC 5th Power Plan. The demand-side resource avoided cost estimate is based on the NWPPC's estimate of the levelized Mid-C (Mid-Columbia) market price for 20 years. The coal plant cost estimate is based on information in Technical Appendix I to the NWPPC 5th Power Plan regarding the technical characteristics, cost, and performance assumptions for resources and technologies expected to be available to meet bulk power generation needs during the planning period.[101] CELP's witness, Orndorff, also testified that the expected cost of new

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[99] See Docket N2005.12.172, NWE's 2005 Electric Default Supply Procurement Plan, Volume 1, Chapter 2, p. 6 and Docket D2004.6.90, Order No. 6574e, paragraph 188. In Order 6574e the PSC authorized NWE to expense investments in demand side resources to send a clear message to NWE that it should aggressively move forward to acquire the 100 aMW identified in its planning.

[100] Id. Chapter 4, p. 11.

[101] Id. Chapter 4, Sources.

long-term resources is approximately $50.00/MWh.[102] Thus, this option establishes consistency between the avoided costs NWE used to evaluate demand-side resources in its 2005 electric default supply procurement plan, expected costs for incremental supply resources, and avoided cost-based rates paid to QFs.

185. Finally, because QFs that elect Option 1 will all receive the same rate regardless of contract length, the PSC finds a minimum contract length of 7 years is necessary for any QF contract involving Option 1.

186. Option 2. The second long-term rate option consists of two sub-options each of which must reflect wholesale market prices, as follows.

187. Option 2(a): This option must reflect NWE's actual hourly power purchases from the market. That is, on an hourly basis, NWE must compute its highest-cost 25 MWh market purchase. Monthly payments to QFs under this option must reflect for each hour NWE's highest-cost 25 MWh market purchase cost and the QF's corresponding hourly production for the same hour. Thus, all QFs must have their production metered hourly.

188. Option 2(b): This option must reflect, by hour, market prices that are evident from a transparent price index. The PSC finds that the Mid-C daily index price for high load hours and low load hours must be used for this purpose. As with sub-option 2(a), monthly payments to QFs that select sub-option 2(b) must be the Mid-C index corresponding to any given hour and the QF's corresponding production for the same hour.

189. A QF may select a contract length under either sub-option 2(a) or 2(b) of up to 20 years.[103] QFs should receive payment with no more of a lag than the turn around time involved in metering and billing of large retail loads.

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[102] Orndorff's $.05/kwh estimate is based on project development experience in Montana. Only a fixed price, not a fluctuating market price, will provide the necessary assurances for debt service and equity returns. *DR PSC-026*.

[103] For as long as NWE has QF contracts that encompass this second option, NWE must provide the basis for the rate calculations and the purchased power rates paid to QFs.

190. For the foreseeable future, NWE will meet its resource needs, in part, through market purchases. Based on the base-case load forecast in NWE's 2005 electric default supply resource procurement plan, in 2007, with its recent power purchase agreement with PPL Montana, NWE will purchase approximately 30 percent of its resource needs from the market. Over the term of the PPL Montana agreement, and if no other resources are acquired, market purchases will grow to over 70% of load. Through auctions, however, NWE may acquire relatively short-term products (3-5 years) that keep its market exposure to between 10% and 30%. These purchases as well as others involving existing QF contracts will not be the basis of the rates in this second long-term rate option. Also, and in contrast, acquisition of 50 MW of new QF wind power would represent approximately 2% of NWE's projected load, assuming the wind resources produce at a 35% capacity factor. Thus, NWE's ratepayers would not experience increased risk as a result of this QF rate option.

Other Long-term, Standard Tariff Issues

191. Because NWE was not consistent in its proposals regarding the mix of energy and capacity rates for the long-term, standard tariff, the PSC finds, for simplicity reasons, that each of the above long-term rate options should reflect a single rate element. This price structure is consistent with the current QF-1 tariff, which NWE proposed, as well as the price structure in the NWE-PPL Montana power purchase agreement.

192. The resources underlying Option 1 must be refreshed periodically. The PSC determines NWE must file to update the prices in Option 1 every two years following receipt of PSC comments on NWE's biennial electric default supply plans *(see ARM 38.5.8226)*. Thus, NWE's electric default supply plans should develop avoided costs for use in updating the prices in Option 1. The refreshed Option 1, once approved by the PSC, would be applicable to prospective QFs, but would not affect then-existing QF contracts executed prior to the PSC's approval of refreshed Option 1 tariff provisions.

193. The PSC finds that the long-term, standard rate options must be available to QFs 10 MW or less. This threshold appears reasonable given thresholds and orders adopted in other states (*e.g.*, Oregon, Idaho) and admitted into evidence in this proceeding, and FERC's recent rules implementing the 2005 Energy Policy Act. With this order the PSC also establishes a 50 MW installed capacity limit on new QFs entering contracts under the long-term standard rate options. Once the 50 MW installed capacity limit is reached, the PSC will consider whether to review its QF policies. The most desirable result would be a diverse mix of new, small QF resources (*e.g.*, small hydro, biomass, cogeneration, wind). The PSC will not establish, a priori, specific set-asides for each possible QF technology. However, the PSC may act in the future to assure diversity prior to reaching the 50 MW installed capacity limit.

Wind-Generated Electricity

194. Wind is a unique resource. Wind-generated electricity production is highly variable and presents particular challenges with regard to day-ahead and hour-ahead system planning, and intra-hour system operations. NWE has experienced more challenges integrating the Judith Gap project and other smaller wind resources than other utilities in the Western Electricity Coordinating Council (WECC) reliability region due to its relatively small control area, lack of owned or dispatchable resources, and a limited and relatively expensive ancillary services-integration market. The intra-hour variability of wind generation in NWE's control area has reduced system stability and reliability and led to violations of WECC standards. The PSC continues to support wind resources within NWE's default supply resource portfolio. However, wind's unique production characteristics must be considered in developing standard rates under PURPA. Unfortunately, the evidentiary record in this proceeding on integration costs and their effect on NWE's avoidable costs is quite limited.

195. NWE's experience with Judith Gap demonstrates that there are incremental costs unique to integrating wind resources. In order to preserve the principle of customer indifference to a utility's purchase of QF power in place of the power the utility would otherwise have acquired but for purchasing from the QF, the PSC finds that it is

reasonable to establish an estimate of incremental integration costs for QFs using wind generators. As for the value for incremental wind integration costs, the PSC identified a likely range of $5.00/MWh to $10.00/MWh in PSC Order No. 6633b, PSC Docket No. D2005.2.14 (see ¶ 202). While the incremental cost of regulating capacity needed to integrate Judith Gap appears to be approximately $5.00/MWh today (see NWE's June 2006 electric default supply tracker filing, PSC Docket No. D2006.5.66), the sustainability of these costs over the long-term is questionable given the limited market for ancillary services and growing regional wind production. On the other hand, geographic diversity from new QF wind resource may help reduce overall integration costs. Due to the uncertainty of both market power prices and ancillary service costs, the PSC establishes a $7.50/MWh proxy integration cost for QFs entering contracts under the standard long-term rate options. That is, wind QFs that do not separately arrange for integration services, but instead rely on NWE to integrate the intermittent energy delivered by the project, must pay NWE $7.50/MWh for each MWh delivered. Importantly, wind resource developers have the option of negotiating project-specific rates that reflect specific project characteristics, such as scheduling and forecasting accuracy, firming capability (*e.g.*, storage, companion resource pairing), and location.

Renewable Energy Credits

196. TDW and NWE agree that the treatment of RECs in QF transactions need not be addressed in the long-term, standard QF tariffs. The PSC agrees. The treatment of RECs in contracts executed under the standard long-term rate options will be left to negotiation between NWE and QFs. Consequently, the PSC will not attempt to adjust the avoided cost bases for the long-term rate options to reflect the value of RECs. The PSC may consider the treatment of RECs in any petition for a PSC-determined project-specific rate filed by a QF larger than 10 MWs. NWE will need to continuously evaluate its REC status under Montana's renewable resource standard requirements.

CONCLUSIONS OF LAW

197. All PSC statements in the above paragraphs, whether generally categorized as introductory, findings, discussions, determinations, or other, that can properly be considered conclusions of law and that should be considered as such are incorporated herein as conclusions of law.

198. NWE is a "public utility" within the meaning of that term as applied in Montana laws pertaining to public utility regulation administered by the PSC. *See e.g. § 69-3-101, MCA.* As a part of NWE's public utility operations NWE supplies electricity in a manner regulated by the PSC and NWE is therefore a "utility" and "electric utility" within the meaning of those terms as applied in Montana and federal laws administered by the PSC and related to utility obligations to purchase power from small power production facilities. *See e.g. § 69-3-601(4), MCA.*

199. NWE's applications in these three consolidated dockets have been properly noticed, processed, and heard in accordance with the procedural laws governing matters before the PSC, including provisions within the Montana Administrative Procedure Act, *Title 2, Ch. 4, MCA,* the procedural requirements of the statutes governing PSC procedures, *Title 69, MCA*, the procedural rules of the PSC, *ARM Title 38, Ch. 2*, and all PSC procedural orders governing these consolidated dockets.

ORDER

IT IS HEREBY ORDERED that NWE shall comply with the PSC determinations and directives of this final order. NWE shall file tariffs reflecting the determinations and directives of this final order.

Except for pending objections, motions, and arguments reserved for future PSC action in these consolidated dockets, all pending objections, motions, and arguments not specifically ruled on in this final order shall be deemed denied, to the extent that such denial is consistent with this final order.

Done and dated this 12th day of December, 2006, by a vote of 3 - 2.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

GREG JERGESON, Chairman

BRAD MOLNAR, Vice Chairman
Voting to Dissent

DOUG MOOD, Commissioner
Voting to Dissent

ROBERT H. RANEY, Commissioner

THOMAS J. SCHNEIDER, Commissioner

ATTEST:

Connie Jones
Commission Secretary

(SEAL)

NOTE: Any interested party may request that the PSC reconsider this decision. A motion to reconsider must be filed within ten (10) days or the service date of this order. *See ARM 38.2.4806.*